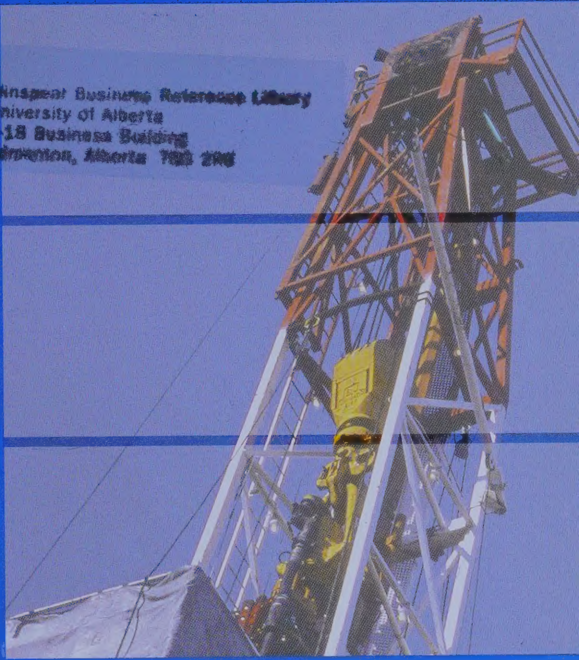


Canadian Natural

The Premium Value
Defined Growth
Independent

ANNUAL REPORT 2004

Table of contents

General Information

Company definition

Throughout the annual report, Canadian Natural Resources Limited is referred to as "us", "we", "our","Canadian Natural", or the "Company".

Currency

All amounts are reported in Canadian currency unless otherwise stated.

Abbreviations

AECO	Alberta natural gas reference location
AIF	Annual Information Form
bbl	barrel
bbl/d	barrels per day
bcf	billion cubic feet
bcf/d	billion cubic feet per day
bcfe	billion cubic feet equivalent
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
C$	Canadian dollars
CSS	Cyclic Steam Stimulation
EOR	Enhanced Oil Recovery
E&P	Exploration and Production
FPSO	Floating, Production, Storage and Offtake Vessel
FPV	Floating Production Vessel
Horizon Project	Horizon Oil Sands Project
mbbl	thousand barrels
mbbl/d	thousand barrels per day
mboe	thousand barrels of oil equivalent
mboe/d	thousand barrels of oil equivalent per day
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mcfe/d	thousand cubic feet equivalent per day
mmbbl	million barrels
mmbbl/d	million barrels per day
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf/d	million cubic feet per day
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
Petrovera	Petrovera Partnership
Rio Alto	Rio Alto Exploration Ltd.
SAGD	Steam Assisted Gravity Drainage
SCO	Synthetic light crude oil
tcf	trillion cubic feet
TSX	Toronto Stock Exchange
UK	United Kingdom
US	United States
US$	United States dollars
WCSB	Western Canadian Sedimentary Basin
WTI	West Texas Intermediate barrel

Cautionary statements

Certain information regarding the Company contained herein may constitute forward-looking statements under applicable securities laws. Such statements are subject to known or unknown risks and uncertainties that may cause actual results to differ materially from those anticipated or implied in the forward-looking statements. Please refer to page 39 for the complete special note regarding forward-looking statements.

All production, sales and reserve statistics represent Canadian Natural's working interest amounts before deduction of royalties unless stated otherwise. Where volumes are reported in barrels of oil equivalent ("boe"), natural gas is converted to oil at six thousand cubic feet per barrel unless otherwise noted. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Methodologies for determining annual reserves are described on pages 11-15.

This report also includes references to financial measures commonly used in the oil and gas industry that are not defined by Generally Accepted Accounting Principles ("GAAP"). The Company uses these measures to evaluate the performance of its business segments, however they should not be considered an alternative to or more meaningful than net earnings.

Common share dividend

Dividends are paid on the first day of January, April, July and October of each year commencing in April 2001.

The following table restated for the two-for-one subdivision of the common shares which occurred in May 2004 shows the aggregate amount of the cash dividends declared per common share of the Company in each of its last four years ended December 31.

	2004	2003	2002	2001
Cash dividends declared per common share	**$ 0.40**	$ 0.30	$ 0.25	$ 0.20

Notice of annual and special meeting

Canadian Natural's Annual and Special Meeting of the Shareholders will be held on Thursday, May 5, 2005 at 3:00 p.m. Mountain Daylight Time in Macleod Hall C/D, of the Telus Convention Centre, Calgary, Alberta. All shareholders are invited to attend.

Metric conversion chart

To convert	**To**	**Multiply by**
barrels	cubic metres	0.159
thousand cubic feet	cubic metres	28.174
feet	metres	0.305
miles	kilometres	1.609
acres	hectares	0.405
tonnes	tons	1.102

Canadian Natural

The Future, Clearly Defined

Mission Statement

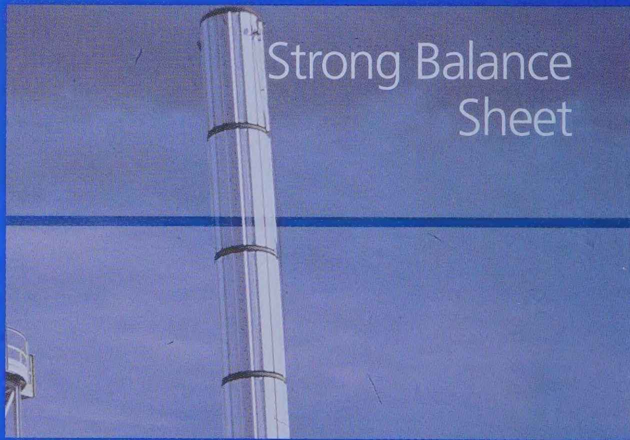
To develop people to work together to create value for the Company's shareholders by doing it right with fun and integrity.

Proven Track Record

Our history of value creation is driven by our focus on four key per-share metrics. We believe that growing production, reserves, cash flow and net asset value will deliver superior returns to our shareholders.

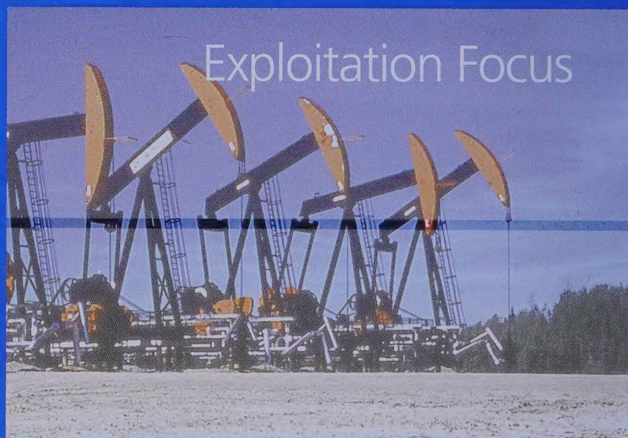
Strong Balance Sheet

We believe that a strong balance sheet increases Canadian Natural's flexibility and allows us to aggressively pursue growth opportunities.



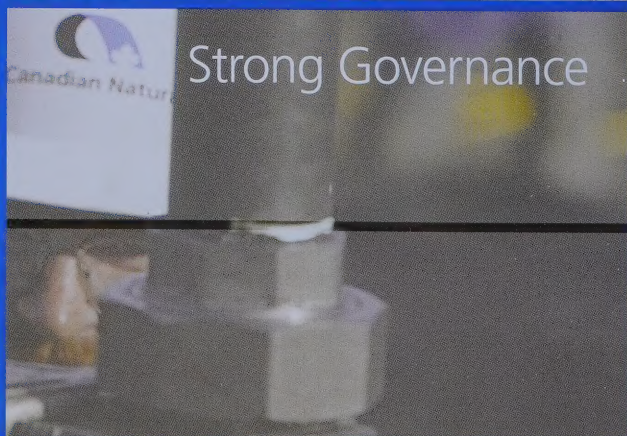
Exploitation Focus

Concentrated land holdings in our core regions give us superior knowledge and cost advantages for our geological plays. This creates drill bit and acquisition opportunities that are maximized through our exploitation core competency - significantly reducing our risk profile.

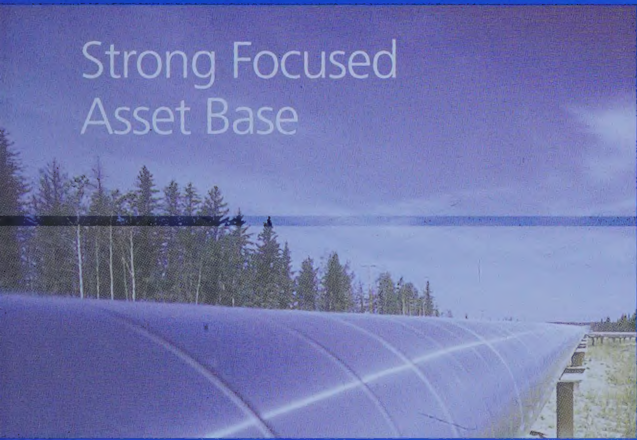


Strong Governance

We maintain strong internal controls and transparent financial reporting. We operate in an ethical and responsible manner. We live in the communities in which we operate.

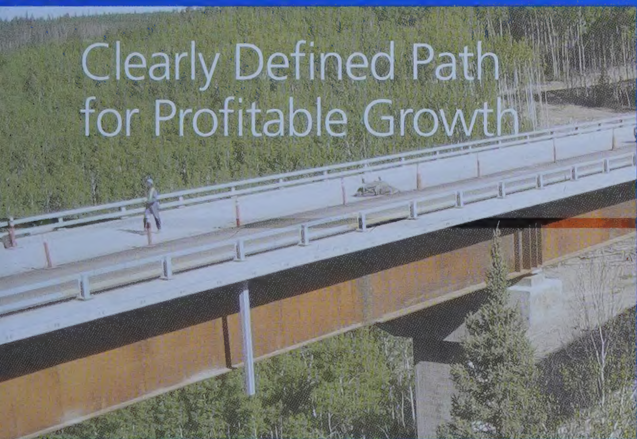


Strong Focused Asset Base



Our operations are focused in regions where we dominate the land base and infrastructure. We operate and maintain high working interests. This combination facilitates cost control and creates new opportunities.

Clearly Defined Path for Profitable Growth



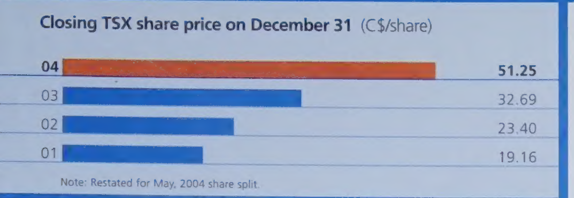
Our five- and ten-year planning processes allow us to define where our future growth will come from. Our exploitation approach reduces the risks associated with achieving those targets. Our deep project inventory provides flexibility for capital allocation under various commodity price scenarios.

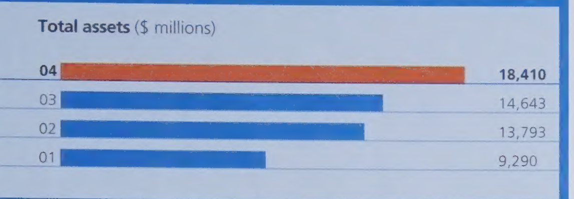
Long-Term Vision

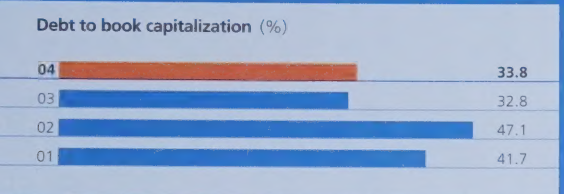
We consider long-term trends and requirements to maximize value. This is reflected in our past strategic acquisitions of natural gas, international and oil sands assets, as well as in our proactive marketing plans and technology research.

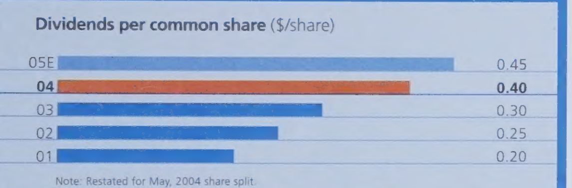
Sustainable Development

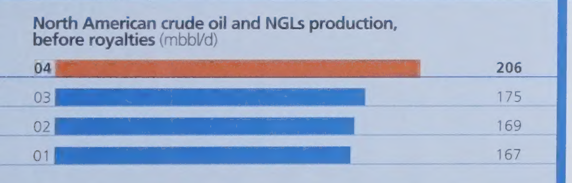
In our conventional operations we ensure that adequate inventories of undeveloped land bolster our future development plans. Our in-situ production and open pit mining of oil sands deposits will allow for decades of future production with little or no annual production declines. We are one of the most sustainable independent energy producers in the world.

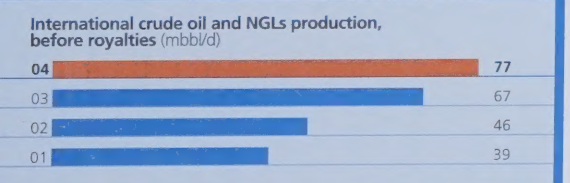


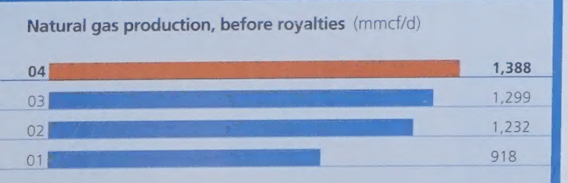


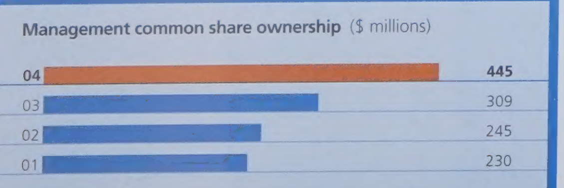












Proven track record

Our past growth rate and highly profitable results have led us to become one of the strongest stock market performers. We have continued to adhere to our strategies, enabling us to build a solid, balanced portfolio of assets. As we enter 2005, our project portfolio is deep and our balance sheet is strong. Our risk profile remains low and our prospects for above average future growth are excellent.

Strong balance sheet

Our balance sheet remains strong as we move into the major expenditure period associated with the construction of the Horizon Oil Sands Project. We exited 2004 with $2.8 billion of debt capacity and have predicated our future financial plans on US$28/bbl WTI pricing. With these assumptions, we would expect debt to book capitalization to peak at under 45% in 2008, reducing significantly thereafter. To gain further financial confidence, we have augmented our plan with an expanded commodity hedging program. This financial plan enables us to retain a 100% working interest in the Horizon Project without compromising our conventional oil and natural gas growth plans.

Exploitation focus

Exploitation of oil and natural gas properties is one of our core competencies. Geological and drilling risks are greatly reduced in comparison with pure exploration opportunities. Additionally, our approach facilitates operating cost reductions which in turn means that we can extend field lives and effectively add reserves simply by improving the economics. The use of technology is key to improving reservoir recovery factors by using our extensive knowledge and experience with EOR techniques. Our strong geological knowledge in our core regions is also levered into lowering the risks associated with new exploration in these areas. We expend a small portion of each year's capital budget into these higher impact opportunities. Our success is evidenced by our discoveries such as Baobab in Côte d'Ivoire, Playfair in the North Sea and successful deep natural gas programs in western Canada.

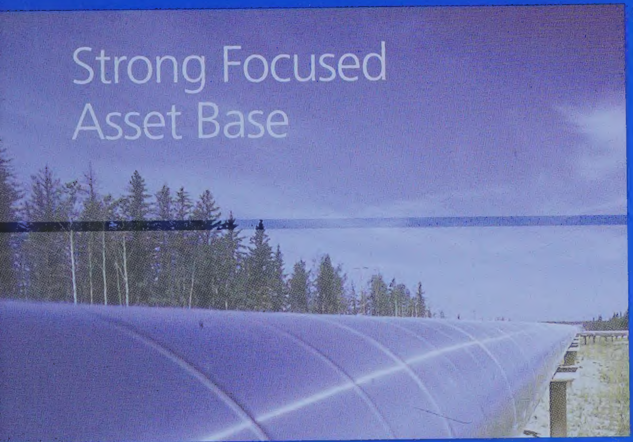
Strong governance

Our Board of Directors and Management Team are aligned with our shareholders because they are shareholders. In excess of $445 million of long ownership was held by this group at the end of 2004. That means that we show discipline to create value over the long run rather than chasing the current hot trend in the market. We have not wavered from our strategies and will not in the future.

Our Board of Directors has been bolstered through the appointment of new independent directors over the past two years. Our financial reporting and disclosures remain among the most transparent in our peer group.

Finally, we do not compromise on how we conduct our affairs, consistently adhering to high environmental and safety standards throughout our worldwide operations.

Strong Focused Asset Base



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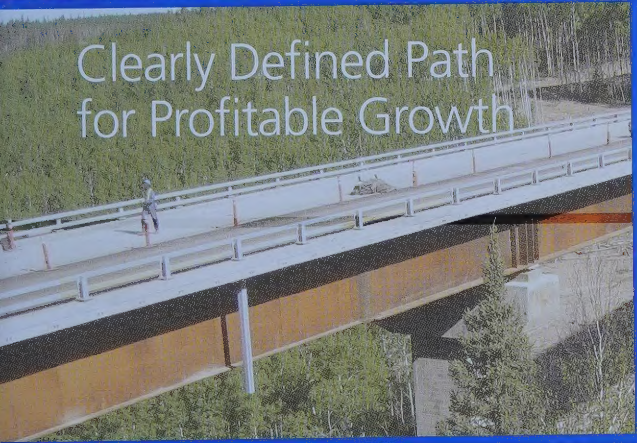
Clearly Defined Path for Profitable Growth



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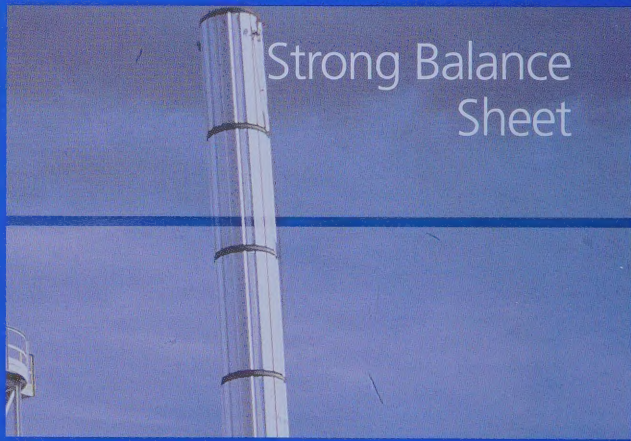
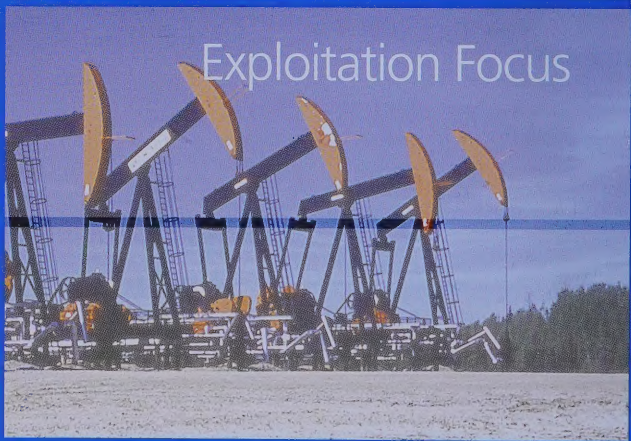


We believe that a strong balance sheet increases Canadian Natural's flexibility and allows us to aggressively pursue growth opportunities.

Exploitation Focus



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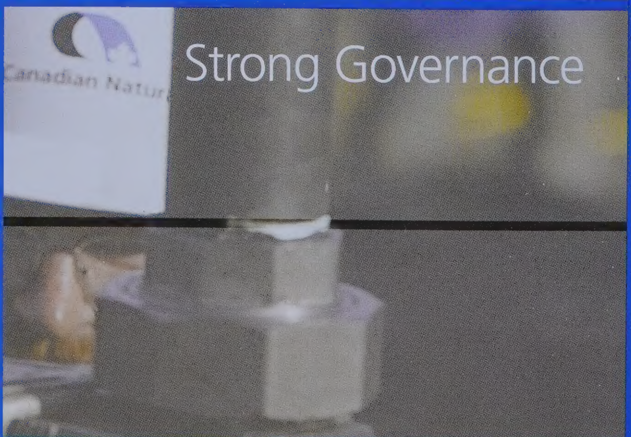
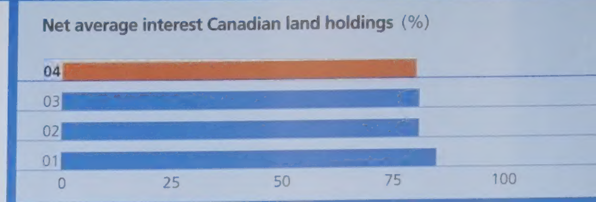
Strong Governance



We maintain strong internal controls and transparent financial reporting.
We operate in an ethical and responsible manner.
We live in the communities in which we operate.

Strong focused asset base

We have a very large concentration of property holdings in each of the basins in which we operate. This allows us to increase utilization rates and control costs per unit. We also maintain high working interests and operate virtually all our assets. This allows us to develop properties according to our plan for maximizing value and within our own time frame. This focus gives us a competitive advantage in that we are able to gain a superior knowledge of geology, operating parameters, and critical success factors in the basins in which we operate.

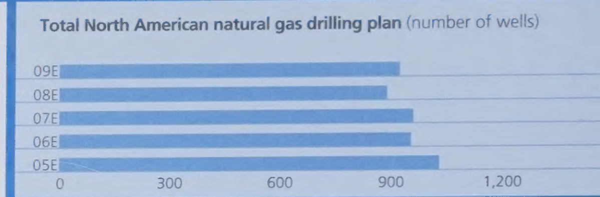


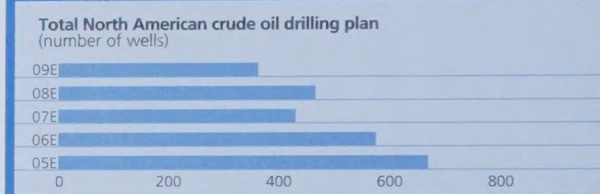
Clearly defined path for profitable growth

Our future growth plans are transparent and low risk. Growth will accrue from three development projects as well as exploitation growth.

In Côte d'Ivoire, the proved developments at Baobab and Espoir will add about 24 mbbl/d of new exit production in 2005 and an additional 18 mboe/d in 2006. In Canada, our proved thermal development at Primrose will add 30 mbbl/d of new production in 2006.

Our natural gas production in Canada is expected to grow by about 5% per annum while our North Sea oil and Canadian heavy crude oil assets benefit from continued exploitation work, maintaining production at 2004 exit levels. Overall, we expect production growth of about 10% per annum. This plan is predicated upon all projects being evaluated at a flat US$28/bbl WTI oil price for 2006 and beyond.

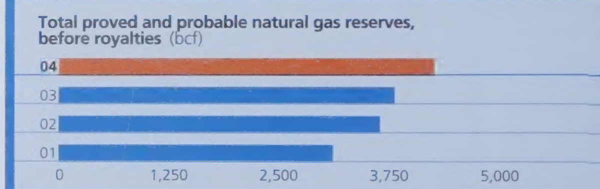


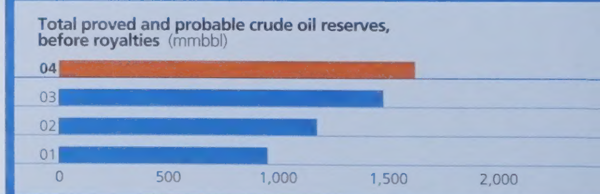


Long-term vision

Operating the assets is only part of the plan. We look at the business from a holistic perspective. For example, our disciplined approach will not allow us to accelerate development of heavy oil properties until the market is able to absorb the product. Our proactive heavy oil marketing strategies were first articulated in 2003 and we continue to deliver on them. The ability to blend is in place and our blended products are reaching expanded markets. We are negotiating with pipeline companies to expand our geographic reach and expect to move into new markets within the next year. Finally, we continue to encourage new conversion capacity to be built in our traditional markets.

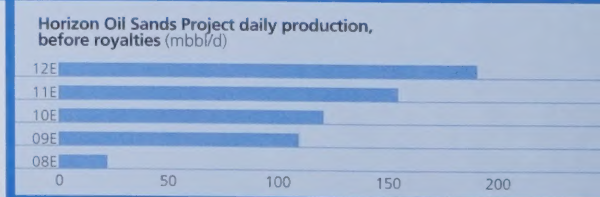
Our long-term vision also extends into the use of new technologies to maximize the recovery of our existing reservoirs. One of our most visible projects is to enhance our Pelican Lake recovery factors, enabling us to examine new approaches and technologies for all of our assets.

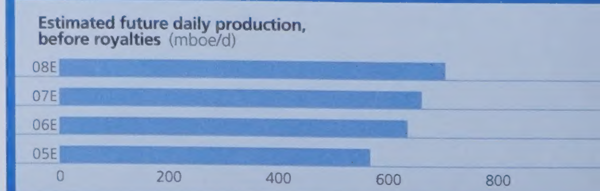




Sustainable development

The inputs for sustainable development are technology and land. While our exploitation approach allows for greater recovery of existing resources, we also keep our prospect inventory high. We have ample undeveloped land inventories for years to come and actively build that base, as appropriate, each year. New play types on existing developed land are constantly reviewed – a good example of this is the regional Notikewin play located in geological zones shallower than those previously developed in Northeast British Columbia. Certainly, the Horizon Project represents an exceptional legacy asset. The resource base is estimated at 6 billion barrels and given the nature of oil sands mining, once operating, ongoing capital costs are minimal. The result is that very significant free cash flow will be generated from this asset, literally for decades to come. This greatly transforms the risk profile and financial prospects of our Company.





Financial Highlights

	2004	2003[1]	2002[1]
FINANCIAL ($ millions, except per share data)			
Revenue, before royalties	**$ 7,547**	$ 6,155	$ 4,459
Net earnings	**$ 1,405**	$ 1,403	$ 539
Per common share – basic [2]	**$ 5.24**	$ 5.23	$ 2.11
– diluted [2]	**$ 5.20**	$ 5.06	$ 2.04
Cash flow from operations [4]	**$ 3,769**	$ 3,160	$ 2,254
Per common share – basic [2]	**$ 14.06**	$ 11.77	$ 8.82
– diluted [2]	**$ 13.98**	$ 11.53	$ 8.50
Capital expenditures, net of dispositions [3]	**$ 4,633**	$ 2,506	$ 4,069
Long-term debt	**$ 3,538**	$ 2,748	$ 4,200
Shareholders' equity	**$ 7,324**	$ 6,006	$ 4,754
OPERATING			
Daily production, before royalties			
Crude oil and NGLs (mbbl/d)			
North America	**206**	175	169
North Sea	**65**	57	39
Offshore West Africa	**12**	10	7
	283	242	215
Natural gas (mmcf/d)			
North America	**1,330**	1,245	1,204
North Sea	**50**	46	27
Offshore West Africa	**8**	8	1
	1,388	1,299	1,232
Barrel of oil equivalent (mboe/d)	**514**	459	421
Average prices, before royalties [5]			
Crude oil and NGLs ($/bbl)			
North America	**$ 33.16**	$ 29.40	$ 28.77
North Sea	**$ 51.37**	$ 42.00	$ 40.32
Offshore West Africa	**$ 49.05**	$ 36.47	$ 40.10
Company average	**$ 37.99**	$ 32.66	$ 31.22
Natural gas ($/mcf)			
North America	**$ 6.61**	$ 6.34	$ 3.79
North Sea	**$ 3.73**	$ 3.03	$ 2.75
Offshore West Africa	**$ 5.25**	$ 4.37	$ 4.82
Company average	**$ 6.50**	$ 6.21	$ 3.77

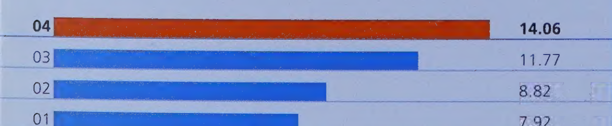
(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) Restated to reflect two-for-one share split in May 2004.

(3) In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as Petrovera, for $471 million. The acquisition is included in the results of operations commencing February 2004. In 2002, the Company paid cash of $850 million and issued 20,016,436 common shares to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement. The Rio Alto acquisition is included in the results of operations commencing July 2002.

Our Four Value Creation Metrics

Cash flow from operations per common share ($/share)

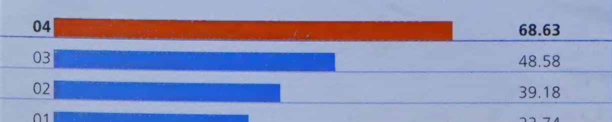


Note: Restated for May, 2004 share split.

Daily production, before royalties per 1,000 common shares (boe/d)

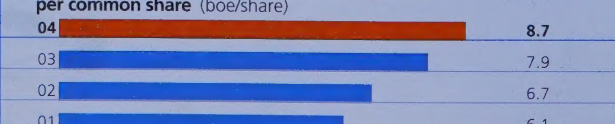
Note: Restated for May, 2004 share split.

Pretax net asset value per common share ($/share)



Note: Restated for May, 2004 share split.

Proved and probable reserves, before royalties per common share (boe/share)



Note: Restated for May, 2004 share split.

Drilling activity (net wells, excluding stratigraphic test/service wells)	2004	2003	2002
North America	**1,099**	1,338	444
North Sea	**11**	13	5
Offshore West Africa	**3**	2	4
	1,113	1,353	453

Core undeveloped land holdings (thousands of net acres)			
North America	**11,523**	9,811	10,213
North Sea	**565**	573	410
Offshore West Africa	**886**	943	943

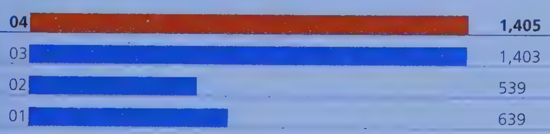
Proved reserves, before royalties			
Crude oil and NGLs (mmbbl)			
North America	**695**	672	665
North Sea	**303**	222	203
Offshore West Africa	**125**	106	94
	1,123	1,000	962
Natural gas (bcf)			
North America	**3,202**	3,006	3,048
North Sea	**27**	62	71
Offshore West Africa	**81**	86	90
	3,310	3,154	3,209
Barrels of oil equivalent (mmboe)	**1,674**	1,526	1,497

Proved reserves, after royalties			
Crude oil and NGLs (mmbbl)			
North America	**648**	588	571
North Sea	**303**	222	202
Offshore West Africa	**115**	85	75
	1,066	895	848
Natural gas (bcf)			
North America	**2,591**	2,426	2,446
North Sea	**27**	62	71
Offshore West Africa	**72**	64	71
	2,690	2,552	2,588
Barrels of oil equivalent (mmboe)	**1,514**	1,320	1,279

(4) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on net earnings and cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

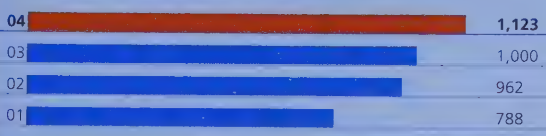
(5) Including transportation costs and excluding risk management activities.

Net earnings ($ millions)



Cash flow from operations ($ millions)

Total proved crude oil reserves, before royalties (mmbbl)



Total proved natural gas reserves, before royalties (bcf)

Letter to Shareholders

We exited 2004 as an exceptionally strong company. Our project portfolio is robust, our team has depth and our financial strength is amongst the best in our peer group. We remain focused on delivering shareholder value and have generated a 23 percent annual growth rate in net asset value over the past five years while at the same time controlling operating and capital costs.

Over the next five years we expect to continue to deliver five percent average annual growth rates in western Canadian natural gas volumes and 10 percent per annum on an overall basis. Our Canadian and North Sea assets capitalize on our core competency of mature basin expertise. Offshore West Africa adds high potential exploration opportunities backstopped by a solid growing production base. We will soon add a world-class oil sands mining development that will in many ways reduce our corporate risk profile and greatly increase the sustainability and reliability of our annual cash flows. We remain committed to the capital allocation strategy that has so effectively positioned us where we are today.

As we embark upon the construction of the Horizon Oil Sands Project ("Horizon Project"), the basic tenets of our defined plan are becoming more transparent. We have been formulating this plan for the past few years with the following guiding principles:

- Maintain a strong balance sheet and financial discipline. During 2003 we significantly strengthened our balance sheet and this profile was sustained through 2004. Our financial plans fully support the requirements of our ongoing conventional business as well as the construction costs of the Horizon Project.
- Develop a highly profitable conventional asset base that still provides a strong growth profile during the heavy construction years of the Horizon Project. Our pre-investment in long-lead projects such as Baobab, Espoir and Primrose facilitates this profile. These projects reach commercial operations over the next two to three years, providing production growth and free cash flow from investments largely funded in 2003 through 2005. Our low-risk exploitation plan will deliver 10 percent average annual production growth.
- Quantify costs and contain risks on the Horizon Project to a higher level than has previously been achieved in the oil sands. We believe that by having a high degree of project definition we can mitigate the majority of financial, technical and construction risks in the project – greatly enhancing our ability to retain a 100 percent working interest in this world-class project.
- Maintain our focus and augment our world-class team. We have a management structure flexible enough to maintain strong focus on our various businesses. During the past year we have further strengthened the teams required to develop the Horizon Project and we exited 2004 with the leadership team in place and almost 1,300 people working on this project alone.

Discipline, focus and delivery are our strongest attributes. The plan is in place, it is transparent and we will now, as we have in the past, deliver.

2004 conventional operations in review

The business environment in 2004 was strong for the oil and gas industry. Higher than historical commodity pricing resulted in a high demand for technical expertise and virtually all associated services. This, coupled with the appetite of industry and trusts for producing properties, led to significant inflationary pressures.

In this environment our teams have done a remarkable job containing costs. Our conventional proved finding and onstream costs were actually reduced by three percent and our field operating costs were within three percent of 2003 levels. This is directly attributable to our operational strategy of controlling and dominating the land and infrastructure in our core regions. By using our economies of scale and maintaining high utilization rates on centralized facilities we are better able to control costs. Further, the high level of understanding that we gain by focusing our efforts on a few regions enables us to gain a competitive advantage and complete accretive property acquisitions during the year.

In western Canada, three acquisitions were completed. The acquisition of heavy crude oil properties in early 2004 increased our dominance of the heavy crude oil region in eastern Alberta through additional undeveloped land holdings and gains in market share. By leveraging our already large infrastructure we were able to immediately effect $0.60 per barrel operating cost reductions on these acquired properties. The spring 2004 acquisition of properties in Northeast British Columbia and Northwest Alberta significantly deepened our natural gas project portfolio, particularly for Foothills deep gas in both core regions. This was followed by the fall 2004 acquisition of properties that strengthened both our natural gas assets, including Foothills land positions, and our light crude oil portfolio.

In the North Sea, we opened a new hub in the central North Sea by acquiring high working interest, operated positions at the T & B Blocks. These crude oil producing Blocks will focus on exploitation activities in upcoming years along with our other three hubs at Ninian, Murchison and Banff/Kyle. The exploitation opportunities on T & B Block are similar to those we have successfully converted at Ninian and Murchison.

Growth through the drill bit was also strong, even following our disciplined reallocation of capital from crude oil drilling to help finance the above acquisitions. We organically grew our entry to exit natural gas production by about five percent, a significant accomplishment given that basin production levels are declining. Our defined growth plan forecasts 10 percent per annum organic growth on a boe basis for the next several years.

The business environment late in the fourth quarter of 2004 was significantly impacted by disruptions in the western Canadian synthetic crude oil ("SCO") and heavy crude oil markets. Due to maintenance and equipment failures industry bitumen upgraders were off production in December and bitumen streams normally moved into the SCO market were diverted into the heavy crude oil market. This reduced the amount of upgrading capacity and increased the amount of heavy crude oil on the markets, significantly increasing the price differentials for heavy oil. Diluent costs increased to reflect greater demand requirements. These issues have somewhat abated today; however, we do not expect full recovery until mid-2005. Evidence of this trend is shown with mid-March 2005 heavy crude oil differentials now at 32 percent of WTI, only slightly higher than the long-term average of 30 percent.

These types of market dynamics have occurred in the past and will likely happen in the future. The base dynamics for heavy crude oil, however, remain strong despite these short term aberrations. To partially mitigate these downtimes and in anticipation of significant increases in SCO and heavier crude production by the industry, we have become more aggressive in our heavy crude oil marketing strategies over the past two years.

Blending, the first phase of this strategy, gained significant momentum during 2004. Several refiners currently pipeline connected but not served by Canadian industry tried our SCO/bitumen blended oil called Synbit as an alternative to higher priced imported medium oils. This blending strategy was further expanded by an industry initiative to create a large stream of crude oil comprised of several different blends of current basin production. This product, called Western Canadian Select ("WCS"), will provide refiners with a consistent, large stream of crude oil. New facilities were commissioned in late-2004; and currently, industry shipments of WCS are approximately 250 thousand barrels per day.

The second strategy we are employing is to expand our markets beyond our current geographic area. By working with pipeline companies we are looking to expand these systems into other areas of the United States and even to the west coast of Canada where a deep water port would facilitate large tanker shipments to Asia. These expansions could significantly increase demand for our products and reduce price volatility.

Finally, in the long-term, we seek to work with refiners themselves to build or expand new upgrading capacity for heavy oil. We continue to believe that one or more such expansions will occur as the current economics are compelling to refiners.

Four key performance metrics

We again exceeded our targeted performance per-share metrics growth, a minimum 10 percent increase per annum in cash flow, production, reserves and net asset value with 2004 increases of 19 percent, 12 percent, 10 percent and 41 percent, respectively.

Horizon Oil Sands Project

This world-class project seeks the phased mining development of what we estimate to be approximately six billion barrels of bitumen. The project is comprised of both a bitumen mining operation and an onsite upgrader. As it is a mining project, production levels are largely a function of the size of available infrastructure and are not subject to production declines as in conventional hydrocarbon operations. Therefore, most of the investment is up front in nature and large levels of free cash flow are generated from production for decades to come as low levels of capital reinvestment are required.

As a new entrant to this business we have mitigated as many construction and financing risks as possible and in the process have obtained an exceptional definition of both what we will build and, as importantly, how we will build it.

This high level of definition, itself a risk mitigant, has enabled us to obtain fixed bid quotes for approximately 68 percent of Phase 1 construction costs. Furthermore, by virtue of having 21 separate construction components in Phase 1 we have spread the counterparty financial, manpower and construction risks to a wider range of suppliers. This represents the highest level of cost certainty ever achieved in the oil sands industry for this size of project.

Allan P. Markin
Chairman of the Board

N. Murray Edwards
Vice-Chairman of the Board

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Financially, we have integrated our Horizon Project requirements into our conventional operating plans and have formulated a long-term profile that will satisfy all financial obligations while stewarding to our financial targets and growing the conventional business. To further reduce commodity price risks our Board of Directors has authorized a more significant hedging program effectively locking in prices on a portion of our future production at prices much higher than what our financial plans were built upon. We can maintain a 100 percent ownership in the Horizon Project without compromising our financial principles or issuing new equity.

Disciplined delivery

As we enter 2005, our strong project inventory of natural gas and crude oil assets in Canada, the North Sea and Offshore West Africa will continue to deliver exceptional returns to our shareholders. The plan is in place and we will continue to execute that plan. Similarly, we have a highly defined project plan for the Horizon Project and will be just as rigorous and disciplined in the execution of that plan as we are in our conventional business.

As we deliver that clear plan to profitable growth, our stakeholders will be the beneficiaries of the results. We are proud to represent our stakeholders and remain committed to "developing people to work together to create shareholder value by doing it right with fun and integrity".

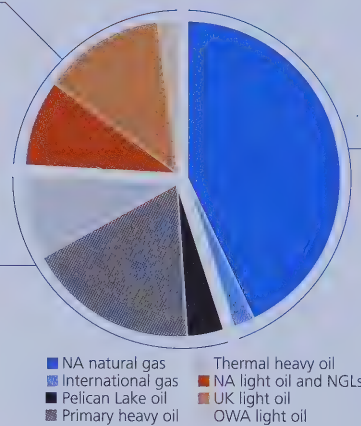
We would also like to thank our team for delivering another exceptional year. We look forward to the continued growth and new opportunities over the coming years.

Review of Operations

Production mix for 2004

Lighter crude oils
(24% in 2004)
In 2005, these volumes will increase both in terms of mix and absolute volume levels due to new production in offshore Côte d'Ivoire and the UK.

Heavier crude oils
(31% in 2004)
In 2005, production levels are expected to remain relatively flat with expected increases in thermal in-situ production in 2006.



Natural gas
(45% in 2004)
In 2005, Canadian volumes (currently 97% of natural gas volumes) are expected to increase by about 5%.

Production

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities we produce; namely natural gas, light crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil. This affords increased development flexibility throughout the business cycle.

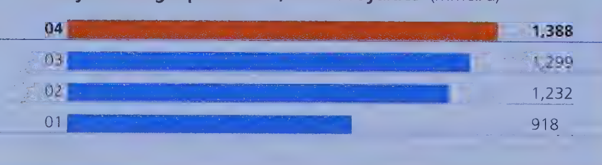
In 2004 we achieved record levels of production. Production before royalties on a barrel of crude oil equivalent was 514 mbbl/d during 2004, up 12% from 2003 levels. Total crude oil and NGLs production before royalties increased by 17% to 283 mbbl/d.

Increases from primary heavy crude oil partially reflected the February 2004 acquisition of about 28 mbbl/d in the Lloydminster area, while North Sea increases included a mid-year acquisition of about about 16 mboe/d. Thermal production increases reflected the commencement of production from new high pressure well pads in mid-2004.

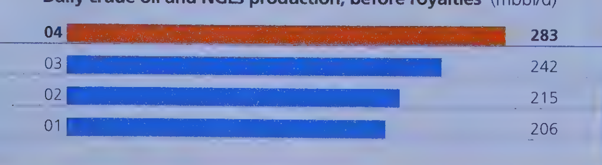
Natural gas production before royalties continues to represent our largest product offering. Natural gas production before royalties for 2004 increased 7% or 89 mmcf/d from 2003 levels. The increase was a result of a successful natural gas drilling program and the acquisition of certain resource properties in Canada.

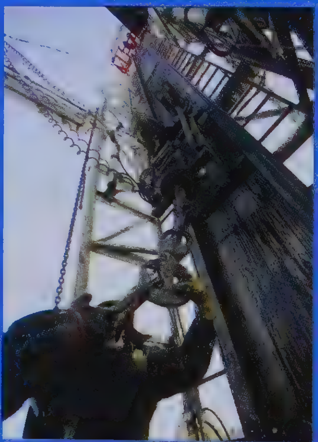
	2004		2003	
(before royalties)	**Production mboe/d**	**Mix %**	Production mboe/d	Mix %
Natural gas	**231**	**45**	217	47
North America light crude oil and NGLs	**47**	**9**	47	10
Pelican Lake crude oil	**20**	**4**	24	5
Primary heavy crude oil	**95**	**18**	66	15
Thermal heavy crude oil	**44**	**9**	38	8
North Sea light crude oil	**65**	**13**	57	13
Offshore West Africa light crude oil	**12**	**2**	10	2
Total	**514**	**100**	459	100

Daily natural gas production, before royalties (mmcf/d)



Daily crude oil and NGLs production, before royalties (mbbl/d)





Mary-Jo E. Case
Vice-President, Land

Tim S. McKay
Senior Vice-President,
North American Operations

Total Canadian land holdings (thousands of net acres)

Canadian net undeveloped land holdings (thousands of net acres)

Seismic

We believe that a disciplined emphasis on geology and geophysics reduces exploration risk and ultimately results in better full cycle economics. Often, it is possible to reduce drilling risk by targeting multi-zone drill locations enabling higher-risk deep prospects to be supported by lower-risk medium and shallow zones.

Canadian Natural continues to add quality locations to its inventory by integrating geological plays with new seismic data. For the year 2004 in Canada, we invested $60.8 million to acquire new seismic and to purchase and reprocess existing seismic data. In total, over 3,622 kilometers of conventional 2-D seismic data and over 240 square kilometers of 3-D seismic data were acquired. Additionally, over 8,199 kilometers of conventional 2-D seismic data and 396 square kilometers of 3-D seismic data were purchased. We continue to acquire this data under stringent environmental controls in a cost effective manner.

In the North Sea, we purchased 2,370 kilometers of 2-D seismic and 1,500 square kilometres of 3-D seismic. We also reprocessed a further 180 square kilometres of 3-D seismic data. This data allows us to continue aggressive in-field and near-field development and exploration. Offshore West Africa saw the purchase of 3,296 kilometers of 2-D seismic data and 123 square kilometres of 3-D seismic as well as the reprocessing of 2,222 square kilometers of 3-D seismic data.

Undeveloped land

Canadian Natural has the second largest undeveloped land inventory in the Western Canadian Sedimentary Basin ("WCSB"). At the end of 2004, our core North American undeveloped net acreage totaled 11.5 million net acres, up 17% from the prior year. Total land holdings, developed and undeveloped, in the WCSB were 16.4 million net acres at the end of 2004, up 19% from 2003. Included in these holdings were approximately 2.1 million net acres of land acquired as part of three property acquisitions completed in western Canada during the year.

This dominant land base provides us the ability to create a defined plan for each of our products and basins. It is an essential building block that allows us to continue to grow production, reserves and value in our core regions. It is also integral to maintaining a low cost structure; additional opportunities in our core regions maintain high utilization of existing infrastructure and reduce capital costs with concentrated, well planned exploration, exploitation and production programs.

Core area dominance of both land and infrastructure is a hallmark of Canadian Natural. It is this domination that provides us with a lower operating and capital cost structure that we can also use as leverage on acquisition opportunities. Low costs, play type expertise and access to infrastructure all translate into opportunities and a strategic advantage on acquisitions.

Internationally, our land base has increased to 658 thousand acres in the North Sea, up from 638 thousand acres in 2003. Offshore West Africa acreage declined slightly to 891 thousand acres.

Our overall average land holding working interest in Canada, reflects the Company's philosophy of maintaining high ownership levels and control of operations. Drilling and development opportunities on our properties are inventoried or developed according to our own defined plans. This flexibility provides us the ability to maintain discipline in capital expenditures. For example, in 2004, many drilling and development projects were deferred as a result of increased capital spending on property acquisitions; flexibility that would have not existed had the Company not controlled and operated these properties.

Core land holdings

	2004			2003		
(thousands of acres)	**Gross**	**Net**	**Net interest %**	Gross	Net	Net interest %
Canada						
Developed	**6,577**	**4,889**	**74**	5,266	4,036	77
Undeveloped	**14,051**	**11,523**	**82**	11,776	9,811	83
	20,628	**16,412**	**80**	17,042	13,847	81
North Sea						
Developed	**138**	**93**	**67**	106	65	61
Undeveloped	**830**	**565**	**68**	804	573	71
Offshore West Africa						
Developed	**8**	**5**	**59**	8	5	59
Undeveloped	**1,672**	**886**	**53**	1,673	943	56
Total						
Developed	**6,723**	**4,987**	**74**	5,380	4,106	76
Undeveloped	**16,553**	**12,974**	**78**	14,253	11,327	85
	23,276	**17,961**	**77**	19,633	15,433	79

Drilling activity

During 2004, we drilled a total of 1,449 net wells, down 19% from 2003 levels reflecting our disciplined reallocation of capital following four major property acquisitions during the year. Our excellent drilling success rate of 91% was similar to the prior year and reflects the exploitation approach that we take to the business.

Year ended December 31	2004			2003	
	Gross	**Net**	**Success**	Net	Success
Crude oil					
North America					
Light oil	**65**	**45**	**97%**	50	94%
Pelican Lake	**34**	**34**	**100%**	39	100%
Primary heavy oil	**207**	**180**	**96%**	316	95%
Thermal heavy oil	**58**	**58**	**100%**	41	100%
North Sea	**10**	**9**	**82%**	11	85%
Offshore West Africa	**4**	**2**	**77%**	1	50%
	378	**328**	**97%**	458	95%
Natural gas – North America					
Northeast British Columbia	**177**	**167**	**89%**	79	78%
Northwest Alberta	**165**	**138**	**92%**	99	85%
Northern Plains	**189**	**163**	**80%**	183	80%
Southern Plains	**270**	**221**	**95%**	416	98%
	801	**689**	**89%**	777	89%
Dry	**106**	**96**		118	
Subtotal	**1,285**	**1,113**	**91%**	1,353	91%
Stratigraphic test / service wells	**339**	**336**		440	
Total	**1,624**	**1,449**		1,793	

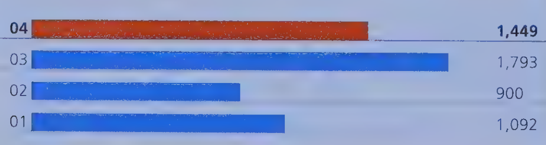
The 43% reduction in primary heavy crude oil drilling was a result of re-inventorying of prospects to future years following the acquisition of the Petrovera properties in early 2004, while the increase in thermal oil drilling reflects the ongoing development of the Primrose property. This project will add approximately 30 mbbl/d of incremental production during 2006.

The focus of natural gas drilling in 2004 shifted to deeper parts of the basin and away from shallow gas drilling in the Southern Plains. The improved success rate in Northeast British Columbia is due to the Notikewin drilling program where success rates of 91% were achieved on an 86 well program.

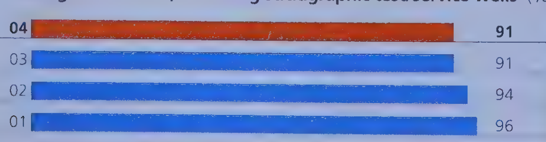
The improvement in Northwest Alberta's results are attributable to an expanded drilling program following the regional Cardium geological study and "best practices" drilling review, both undertaken in 2003. Successful Cardium wells in this area increased to 69 net wells, up from 46 net wells in 2003.

During the year, 218 and 97 stratigraphic appraisal wells were drilled on our oil sands mining and in-situ leases respectively. A total of 21 service wells were drilled including 15 wells at Pelican Lake and three in the North Sea, respectively.

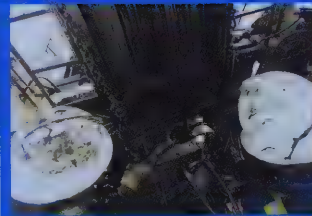
Total net wells drilled



Drilling success rate, excluding stratigraphic test/service wells (%)



Lyle G. Stevens
Senior Vice-President,
Exploitation



Activity by core region

	Net undeveloped land (thousands of net acres)		Drilling activity (net wells)	
	2004	2003	**2004**	2003
Northeast British Columbia	**2,040**	1,566	**192**	106
Northwest Alberta	**1,660**	1,681	**156**	121
Northern Plains	**6,922**	5,627	**613**	717
Southern Plains	**661**	673	**240**	430
Southeast Saskatchewan	**123**	147	**13**	27
Horizon Oil Sands Project	**117**	117	**218**	370
United Kingdom North Sea	**565**	573	**14**	18
Offshore West Africa	**886**	943	**3**	4
	12,974	11,327	**1,449**	1,793

Reserves

Independent evaluation

For the year ended December 31, 2004, we retained independent qualified reserves evaluators, Sproule Associates Limited ("Sproule") and Ryder Scott Company ("Ryder Scott") to evaluate 100% of the Company's proved and probable crude oil and natural gas reserves and prepare evaluation reports on the Company's reserves ("Evaluation Reports").

Horizon Project oil sands mining reserves are not part of Canadian Natural's year-end reserves disclosure; Horizon Project reserves were evaluated as at February 9, 2005. Gilbert Laustsen Jung Associates Ltd. ("GLJ"), a qualified independent reserves evaluator, was retained by the Reserves Committee to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7.

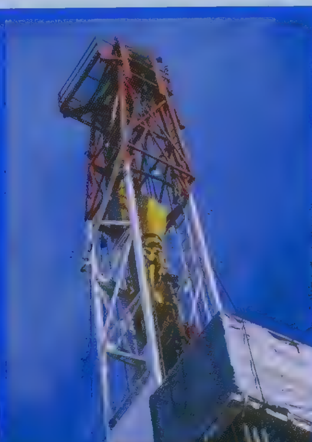
The Board of Directors' Reserves Committee has met with Sproule, Ryder Scott and GLJ and carried out independent due diligence with the evaluators as to the Company's reserves.

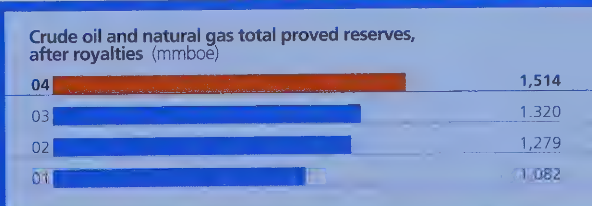
We have been granted an exemption from National Instrument 51-101 – "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), which prescribes the standards for the preparation and disclosure of reserves and reserves related information for companies listed on Canadian stock exchanges. The exemption allows us to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose both proved, and proved and probable reserves, as well as related future net revenues, using forecast prices and costs. Another difference between the two standards lies in the definition of proved reserves.

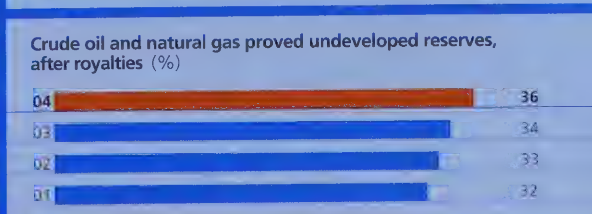
As discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the NI 51-101 and SEC standards is not material.

In accordance with the exemption, we have disclosed proved reserves using constant prices and costs as mandated by the SEC. We have also elected to provide proved and probable reserves and values under the same economic parameters as additional voluntary information.

In the Evaluation Reports, 36% of our total proved crude oil and natural gas reserves are assigned to the proved undeveloped category. Of the proved undeveloped crude oil reserves, 57% are associated with our Primrose thermal project where extensive pool delineation and geological analysis is required to justify continued development and expansion of the project. These reserves are classified as proved undeveloped as a result of this comprehensive reservoir assessment, coupled with a proven economic recovery process and a corporate commitment to development. The other major component of our undeveloped crude oil reserves is associated with our Baobab project in Côte d'Ivoire, accounting for 14% of our proved undeveloped crude oil reserves. This deepwater pool has been delineated with seven wells and is currently under development with first commercial production expected mid-2005.







Reserves replacement and costs

During 2004, we replaced 220% of our conventional production on a total proved reserves basis. This was achieved at a net proved finding and onstream cost of $12.03/boe, a 3% improvement from 2003 results. Our ability to contain costs in an inflationary oil and gas environment is reflective of the disciplined approach that we take. We understand our core regions and the geology within them – effectively maximizing our drilling success rates. We then augment this track record with the economies of scale that our size affords us and our "best practices" reviews of drilling and completion techniques to control costs. The result is more reserves found at a lower cost.

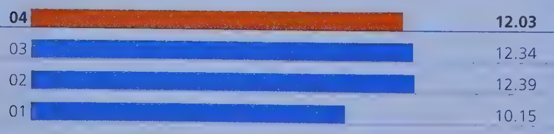
Net reserves classification by product [1]

(as at December 31, 2004)	Proved developed [2]	Proved undeveloped [2]	Proved total [2]	Proved and probable [3]
Light crude oil and NGLs				
North America	6%	–	6%	6%
North Sea	14%	6%	20%	20%
Offshore West Africa	1%	6%	7%	9%
Total	21%	12%	33%	35%
Heavy crude oil				
North America - Pelican Lake	2%	1%	3%	3%
North America - Primary	7%	1%	8%	7%
North America - Thermal	9%	17%	26%	28%
Total	18%	19%	37%	38%
Total crude oil and NGLs				
North America	24%	19%	43%	44%
North Sea	14%	6%	20%	20%
Offshore West Africa	1%	6%	7%	9%
Total	39%	31%	70%	73%
Natural gas				
North America	25%	4%	29%	26%
North Sea	–	–	–	–
Offshore West Africa	–	1%	1%	1%
Total	25%	5%	30%	27%
Total boe	64%	36%	100%	100%

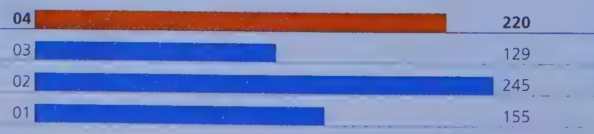
Finding and onstream costs

	2004	2003	2002	Three-year total
Net reserve replacement expenditures ($ millions)	4,259	2,283	3,928	10,470
Reserve additions [4] (mmboe, net of royalties)				
Proved	354	185	317	856
Proved and probable	453	441	356	1,250
Finding and onstream costs [5] ($/boe, net of royalties)				
Proved	12.03	12.34	12.39	12.23
Proved and probable	9.40	5.18	11.03	8.38

Finding and onstream costs, proved, net of royalties ($/boe)



Proved reserves replacement ratio, net of royalties (%)



Net reserves summary – crude oil and natural gas

Reserves, net of royalties (1)	December 31, 2004 Proved developed (2)	Proved undeveloped (2)	Proved total (2)	Proved and probable (3)
Crude oil and NGLs (mmbbl)				
North America	367	281	648	926
North Sea	218	85	303	415
Offshore West Africa	20	95	115	196
	605	461	1,066	1,537
Natural gas (bcf)				
North America	2,213	378	2,591	3,319
North Sea	12	15	27	57
Offshore West Africa	5	67	72	90
	2,230	460	2,690	3,466
Total reserves (mmboe)	976	538	1,514	2,115
Reserve replacement ratio (6) (%)			220	281
Cost to develop (7) ($/boe)				
10% discount	0.85	3.58	1.77	1.78
15% discount	0.73	3.27	1.58	1.56
Present value of reserves (8) ($ millions)				
10% discount	13,739	4,399	18,138	22,937
15% discount	11,838	3,440	15,279	18,802

	December 31, 2003 Proved developed (2)	Proved undeveloped (2)	Proved total (2)	Proved and probable (3)
Crude oil and NGLs (mmbbl)				
North America	348	240	588	857
North Sea	138	84	222	317
Offshore West Africa	23	62	85	133
	509	386	895	1,307
Natural gas (bcf)				
North America	2,140	286	2,426	2,919
North Sea	46	16	62	102
Offshore West Africa	12	52	64	72
	2,198	354	2,552	3,093
Total reserves (mmboe)	875	445	1,320	1,823
Reserve replacement ratio (6) (%)			129	308
Cost to develop (7) ($/boe)				
10% discount	0.24	4.02	1.51	1.60
15% discount	0.22	3.69	1.39	1.44
Present value of reserves (8) ($ millions)				
10% discount	13,080	3,037	16,117	20,167
15% discount	11,222	2,273	13,495	16,460

Oil sands mining reserves, before royalties

The following table sets out, on a company gross basis, Canadian Natural's proved and probable reserves of bitumen and synthetic crude oil from its oil sands mining leases as at February 9, 2005.

Reserves, before royalties	February 9, 2005 Proved	Probable	Proved and probable
Gross oil sands mining reserves (9) (mmbbl)			
Bitumen	1,900	1,420	3,320
Synthetic crude oil	1,560	1,230	2,790

Net reserves reconciliation

Crude oil and NGLs reconciliation (1) (mmbbl, net of royalties)	North America	North Sea	Offshore West Africa	Total
Proved reserves				
Reserves, December 31, 2002 (10)	571	202	75	848
Extensions and discoveries	1	–	13	14
Infill drilling	54	–	–	54
Improved recovery	9	–	–	9
Property purchases	7	27	–	34
Property disposals	–	–	–	–
Production	(56)	(21)	(4)	(81)
Revisions of prior estimates	2	14	1	17
Reserves, December 31, 2003 (2)	588	222	85	895
Extensions and discoveries	**17**	**–**	**–**	**17**
Infill drilling	**24**	**35**	**–**	**59**
Improved recovery	**1**	**10**	**–**	**11**
Property purchases	**36**	**38**	**–**	**74**
Property disposals	**–**	**–**	**–**	**–**
Production	**(66)**	**(24)**	**(4)**	**(94)**
Revisions of prior estimates	**48**	**22**	**34**	**104**
Reserves, December 31, 2004 (2)	**648**	**303**	**115**	**1,066**
Proved and probable reserves				
Reserves, December 31, 2002 (10)	636	277	121	1,034
Extensions and discoveries	1	–	17	18
Infill drilling	58	–	–	58
Improved recovery	25	–	12	37
Property purchases	10	33	–	43
Property disposals	–	–	–	–
Production	(56)	(21)	(4)	(81)
Revisions of prior estimates	183	28	(13)	198
Reserves, December 31, 2003 (3)	857	317	133	1,307
Extensions and discoveries	**20**	**–**	**–**	**20**
Infill drilling	**29**	**49**	**–**	**78**
Improved recovery	**2**	**10**	**–**	**12**
Property purchases	**49**	**49**	**–**	**98**
Property disposals	**–**	**–**	**–**	**–**
Production	**(66)**	**(24)**	**(4)**	**(94)**
Revisions of prior estimates	**35**	**14**	**67**	**116**
Reserves, December 31, 2004 (3)	**926**	**415**	**196**	**1,537**

(1) Reserve estimates and present value calculations are based upon year-end constant reference price assumptions as detailed below.

Reserves evaluation proved constant pricing models

Crude oil and NGLs	Company average price (C$/bbl)	WTI @ Cushing Oklahoma (US$/bbl)	Hardisty Heavy 12° API (C$/bbl)	North Sea Brent (US$/bbl)
December 31, 2004	**32.14**	**44.04 (11)**	**17.45**	**40.47**
December 31, 2003	32.02	32.56	26.16	30.14

Natural gas	Company average price (C$/mcf)	Henry Hub Louisiana (US$/mmbtu)	Alberta AECO C (C$/mmbtu)	British Columbia Huntingdon Sumas (C$/mmbtu)
December 31, 2004	**6.44**	**6.62 (12)**	**6.78**	**6.94**
December 31, 2003	6.63	5.80	6.88	6.94

A foreign exchange rate of US$0.832/C$1.00 was used in the 2004 evaluation. A foreign exchange rate of US$0.77/C$1.00 was used in the 2003 evaluation. A foreign exchange rate of US$0.63/C$1.00 was used in the 2002 evaluation.

(2) 2004 and 2003 proved reserve estimates and values were evaluated in accordance with the SEC requirements. The stated reserves have a reasonable certainty of being economically recoverable using year-end prices and costs held constant throughout the productive life of the properties.

(3) 2004 and 2003 proved and probable reserve estimates and values were evaluated in accordance with the standards of the Canadian Oil and Gas Evaluation Handbook ("COGEH") and as mandated by NI 51-101. The stated reserves have a 50% probability of equaling or exceeding the indicated quantities and were evaluated using year-end costs and prices held constant throughout the productive life of the properties.

Natural gas reconciliation (1) (bcf, net of royalties)	North America	North Sea	Offshore West Africa	Total
Proved reserves				
Reserves, December 31, 2002 (10)	2,446	71	71	2,588
Extensions and discoveries	58	–	6	64
Infill drilling	243	–	–	243
Improved recovery	8	–	–	8
Property purchases	50	19	–	69
Property disposals	(3)	–	–	(3)
Production	(355)	(17)	(3)	(375)
Revisions of prior estimates	(21)	(11)	(10)	(42)
Reserves, December 31, 2003 (2)	2,426	62	64	2,552
Extensions and discoveries	**334**	**–**	**–**	**334**
Infill drilling	**74**	**–**	**–**	**74**
Improved recovery	**6**	**–**	**–**	**6**
Property purchases	**182**	**10**	**–**	**192**
Property disposals	**(8)**	**–**	**–**	**(8)**
Production	**(383)**	**(18)**	**(3)**	**(404)**
Revisions of prior estimates	**(40)**	**(27)**	**11**	**(56)**
Reserves, December 31, 2004 (2)	**2,591**	**27**	**72**	**2,690**
Proved and probable reserves				
Reserves, December 31, 2002 (10)	2,765	89	90	2,944
Extensions and discoveries	72	–	11	83
Infill drilling	285	–	–	285
Improved recovery	26	–	(6)	20
Property purchases	59	22	–	81
Property disposals	(3)	–	–	(3)
Production	(355)	(17)	(3)	(375)
Revisions of prior estimates	70	8	(20)	58
Reserves, December 31, 2003 (3)	2,919	102	72	3,093
Extensions and discoveries	**418**	**–**	**–**	**418**
Infill drilling	**106**	**–**	**–**	**106**
Improved recovery	**6**	**–**	**–**	**6**
Property purchases	**236**	**18**	**–**	**254**
Property disposals	**(10)**	**–**	**–**	**(10)**
Production	**(383)**	**(18)**	**(3)**	**(404)**
Revisions of prior estimates	**27**	**(45)**	**21**	**3**
Reserves, December 31, 2004 (3)	**3,319**	**57**	**90**	**3,466**

(4) Reserves additions are comprised of all categories of reserves changes, exclusive of production.

(5) Reserves finding and onstream costs are determined by dividing total capital costs for each year excluding costs associated with head office, abandonments, midstream and Horizon Project by reserves additions for that year.

(6) Reserve replacement ratios were calculated using annual net reserve additions comprised of all change categories divided by the net production for that year.

(7) Cost to develop represents total future capital for each reserves category excluding abandonment capital divided by the reserves associated with that category.

(8) Present value of reserves are based upon discounted cash flows associated with prices and operating expenses held constant into the future, before income taxes. Only future development costs and abandonment costs have been applied against future net revenues.

(9) Synthetic crude oil reserves are based on upgrading of the bitumen reserves. The values shown for bitumen and synthetic crude oil are not additive.

(10) 2002 reserve estimates were evaluated in accordance with the standards of National Policy 2-B which as now been replaced by NI 51-101. The stated reserves were reasonably evaluated as economically productive using year-end costs and prices held constant throughout the productive life of the properties.

(11) There was no trading of WTI on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for WTI adjusted for the change in the Brent price as posted by Platts Oilgram Price Report.

(12) There was no trading of Henry Hub on December 31, 2004. This posted value was determined on the basis of December 30, 2004 posted price for Henry Hub adjusted for the change in the AECO price as posted by the Canadian Gas Price Reporter.

Marketing

Natural gas

Canadian Natural's realized wellhead price for 2004 was up 5% from 2003 at $6.50 per mcf. The Company's sales portfolio of 1,385 mmcf/d is well diversified with 28% of our sales directly into various American markets, 12% through various Canadian Aggregators and 60% sold directly into our domestic markets. Our portfolio pricing relects prevailing market prices with less than 5% of our sales under fixed price contracts. North American natural gas prices continued their strength in 2004 with the NYMEX price average exceeding the previous year by 12% at US$6.09/mmbtu and the Alberta AECO price averaging C$6.79/mcf, up 1.3% from 2003. The Alberta prices were adversely impacted by higher transportation costs to the markets and the stronger Canadian currency which resulted in a 32.5% wider basis differential at the AECO delivery point.

This sustained favorable pricing environment supported a very active North American drilling program; however, even with record completions, the overall industry production has declined by approximately 1.5% from 2003. This challenging supply scenario is forecast to improve only marginally with continued intense drilling activity in the current year, with exit rates currently anticipated to show a further decline of one percent in 2005.

The North American gas demand continues to increase by about 1.5% annually and to satisfy these markets will require continued intense drilling activity and a significant increase in the quantities of liquified natural gas ("LNG") imported to the US. There are several LNG proposals at various stages of the permitting process and the overall capacity is expected to increase significantly over the next five years. The successful development of coal bed methane in Canada could contribute an additional 1 bcf/d of new supply within ten years. The construction of pipeline capacity to bring the McKenzie Delta and Alaskan gas to markets will also be required over the next decade to meet demand levels. This tight supply scenario should result in a strong pricing environment for North American natural gas for many years to come.

Canadian Natural's natural gas production for 2005 is forecast to average between 1,425 and 1,475 mmcf/d and based on the current pricing strips for NYMEX of US$7.02/mmbtu and AECO of C$7.47/mmbtu, this would yield an overall wellhead price of C$7.32/mcf for the Company's sales portfolio.

Crude oil

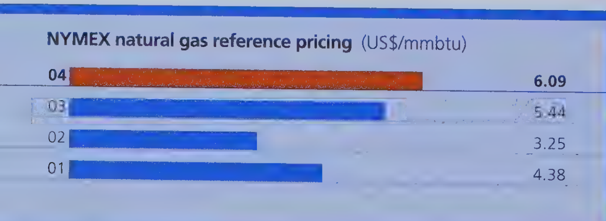
Canadian Natural's realized wellhead price for crude oil and NGLs improved by 16% in 2004 to C$37.99/bbl on total sale volumes of 282.5 mbbl/d.

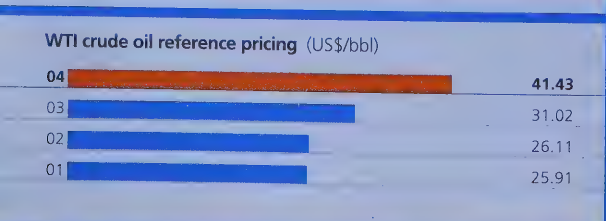
The benchmark prices for crude oil in 2004 were up significantly over 2003 with WTI up 34% at US$41.43/bbl and Brent up 33% at US$38.28/bbl. These prices were negatively impacted by the relative weakness of the U.S. currency during the year.

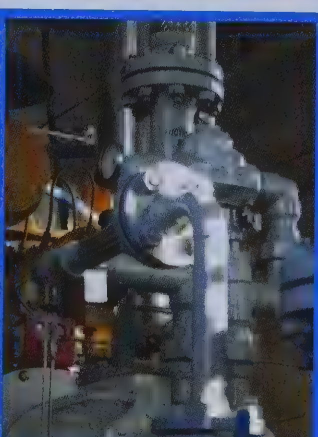
The 2004 price differential between WTI and a typical Lloyd heavy blend widened by 57% to US$13.44/bbl or weakened as a percentage of WTI to 32% from 28% in 2003. This compares with the long-term differential of approximately 30% of WTI over the last ten years. The current market reflects what the premium refiners are currently paying for the lighter and sweeter grades of crude oil that they need to process to meet their required yields of refined products. The fourth quarter was particularly challenging for heavy oil producers when serious disruptions at two major upgrading facilities in Fort McMurray resulted in large incremental volumes of bitumen being marketed in the normally lower demand season. The heavy differential deteriorated to 41% of WTI in the fourth quarter compared to 29% of WTI in the third quarter. The markets for diluents and synthetic crude oil were also impacted by these unusual and temporary events and have somewhat recovered in the first quarter of 2005. The current heavy differential is at 32% of WTI and we expect the affected upgraders to be fully operational by the fall of 2005.

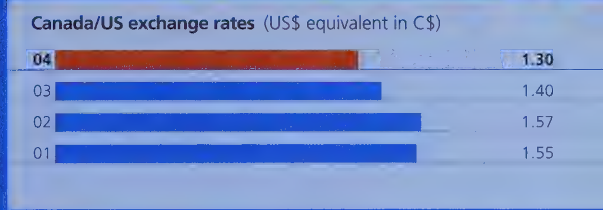
The Company has vast undeveloped heavy crude oil resources that can be economically developed. The challenge for heavy oil producers is to successfully blend various crude types and diluents into feedstocks suitable for the existing refinery configurations in our markets. Our heavy crude oil marketing strategy seeks to extend our geographic reach into new markets and to increase the volumes processed by the existing refinery market. To this end, the Company supports various pipeline projects that would increase or extend our access to refineries located in the US midwest, Gulf Coast areas, west coast areas as well as Asian markets. Canadian Natural has nominated 25 mbbl/d of capacity for 5 years on the proposed Corsicana pipeline reversal from Patoka to the Gulf Coast and is considering its options with respect to other pipeline projects that have yet to conduct their open season phase.

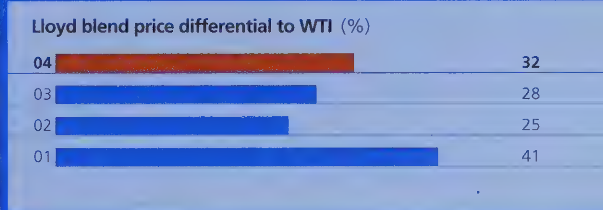
Canadian Natural believes that additional conversion capacity is required to support the large potential production from the Canadian bitumen reserves. Our analysis shows very attractive economics for such refining units and we continue to encourage refiners to add conversion capacity to their existing plants and would consider taking on a more direct role in such projects if appropriate.

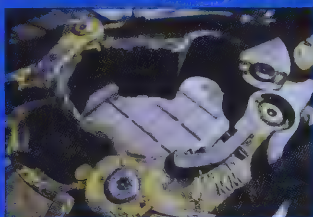


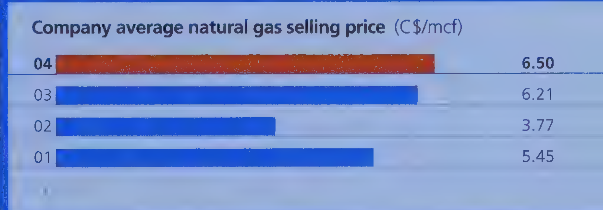




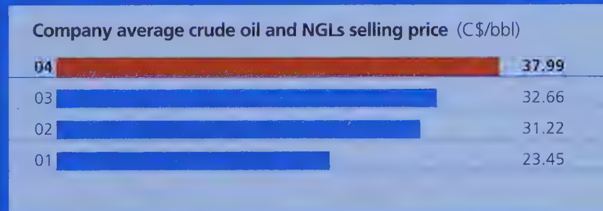








Réal M. Cusson
Senior Vice-President,
Marketing



Canadian Natural has further developed its overall blending strategy and in cooperation with other industry participants, the Company has created a new crude oil blend called WCS. The objective of this strategy is to offer a large stream of consistent quality to our customers. WCS was first marketed in December 2004 and is currently shipping a stream of 250 mbbl/d of which Canadian Natural contributes 125 mbbl/d. The total capacity for this stream is currently 375 mbbl/d and will be increased to 500 mbbl/d by the fall of 2005. WCS not only adds value to refiners, it reduces the overall blending and transportation costs for the producers. WCS resembles a Bow River crude oil with premium quality asphalt characteristics. WCS could potentially become a new benchmark for North American markets and be financially traded similarly to WTI which would bring additional benefits to both refiners and producers.

Canadian Natural's WCS strategy opens markets that previously preferred international medium sour grades to our Canadian heavy crude oil. WCS is able to compete with and displace such medium sour feedstocks. WCS has already been processed by several refiners and the feedback has been positive. The availability of a large stream of known and consistent quality crude oil delivered reliably by pipeline, is a very positive attribute for WCS. Canadian Natural intends to also continue to offer its unique blend of raw bitumen from its ECHO pipeline and synthetic ("Synbit") to refiners.

The overall supply and demand fundamentals are very supportive of a robust pricing environment over the next few years. The demand in the American and Asian markets is very strong, and very large and costly infrastructure programs are required to increase supplies worldwide. There is little spare productive capacity practically available from producers and the logistical challenges are not only costly to resolve but would take a few years to be completed. Based on the current pricing strip of US$53.13/bbl for WTI, differentials of US$18.04/bbl for Lloyd blend and US$2.51/bbl for Brent, our 2005 production portfolio would yield an overall wellhead price of C$42.59/bbl.

Price risk management

Canadian Natural's hedging strategy is to protect our cash flow in order to fund the required capital expenditures for our ongoing development programs. Financial derivatives such as costless collars or put options are used to meet our objectives if deemed appropriate following our risk analysis for the pricing environment of the commodities we produce or consume in our operations. Currency exposures are also monitored and may be hedged in conjunction with commodities.

With the approval of the Horizon Oil Sands Project, the Company's Board of Directors has granted Management the authority to hedge up to 75% of any commodity's expected production volumes for a forward 12 month period, up to 50% of the second 12 month period and up to 25% for the following 24 month period.

Midstream

The Company's midstream assets consist of the 100% owned and operated ECHO Pipeline, the 15% interest in the Cold Lake Pipeline system, the 62% interest in the operated Pelican Lake Pipeline and the 50% interest in the 84 megawatt co-generation unit located at our Primrose facility. The midstream assets allow the Company to control and optimize its transportation costs for approximately 80% of its heavy crude oil production and generate additional revenues from third party volumes and the sale of surplus electricity.

ECHO is the only pipeline delivering raw bitumen to the Hardisty terminals and plays an important role in our heavy crude oil blending and marketing strategy for Synbit and other diluted bitumen blends, including WCS.

Environment, Health & Safety and Community

Responsible operations integral to our disciplined delivery plan

As part of our disciplined delivery plan, we are proactive and accountable to our commitment of responsible operations.

Corporate-wide management systems, built on best practices, support our health and safety, and environmental goals. These evolving systems have kept pace with our rapid growth and provide the tools and processes that enable our employees to meet our mission statement of "doing it right." With these management systems we internally track, report and benchmark our performance and, most importantly, achieve continuous improvement.

We continue to conduct our operations with the diligence necessary to comply to all regulatory standards and guidelines. Our goals of responsible operation are integrated into project planning and execution. Every employees' compensation includes not only our production and economic targets, but also our overall performance related to environment, and health and safety metrics.

We also continue to gain great value from developing and maintaining co-operative working relationships with a diverse range of stakeholders and with the communities where we do business. Whether it is working together with our trucking service providers to minimize spill incidents, participating in multi-stakeholder groups on industry research initiatives, or collaborating on strategies to address greenhouse gas concerns or water management issues, we believe such co-operation is essential.

Applying effective environmental management strategies

In 2004 we continued to demonstrate our effectiveness throughout our North American and International operations by applying strategies that address key issues such as energy efficiency, air emission management, reduction of fresh water use and minimization of our landscape footprint.

Among our successes:

- Gas conservation strategies deliver results. Since 2001 we have invested significant resources, more than $80 million in capital projects, into the application of natural gas conservation schemes at both our thermal and conventional heavy crude oil operations. We have attained impressive results; since 2001: the amount of gas vented has been reduced by 45% while the gas flared has been reduced by 57%.
- Building in efficiencies at our Horizon Oil Sands Project. From the beginning of the Horizon Project efficiency was a key design criteria for the processing of these crude oil resources. The focus is on increasing output while reducing the use of energy resources and air emissions. Greenhouse gas emissions per barrel of crude oil will be 20% less than those of existing operations in the Fort McMurray area. We will also achieve almost complete recovery (99.8%) of sulphur emissions.
- Brackish water initiatives keep ahead of expansion needs. Our ongoing and proposed expansions at Primrose and Wolf Lake have incorporated aggressive strategies for the reduction of fresh water use. The allocation of resources in 2004 to develop brackish water sources is several years ahead of schedule. In 2005, we will be reducing fresh water usage and our brackish water supply will double to 100 mbbl/d.
- Minimizing our footprint essential for our scale of operations. 2004 was an active year with more than 1,000 new wellsite locations and associated roads constructed. By using multi-well pads and horizontal drilling technology, we significantly reduced our footprint. Other measures such as waste management are also integral to reducing our impacts. At our Brintnell and Primrose fields, implementation of waste reduction procedures has resulted in a 75% decrease in the waste volumes needing surface disposal.

Continuous improvement of our health and safety systems

Canadian Natural conducts our operations in a manner that protects the health and safety of employees, contractors, the public and the environment.

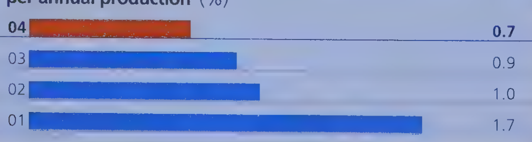
In 2004 we implemented an enhanced Safety Management System at our Canadian operations. This was an important achievement. Annual audits ensure continuous improvement and the full involvement of field and corporate staff in meeting objectives.

Internationally, we have improved our Safety Health and Environment Management System with full roll-out and implementation planned for 2005. We also continue to make strides in extending our current scope of ISO 14001 certification to our Northern North Sea assets. Our recent acquisition of two Central North Sea assets, the Tiffany and Balmoral installations, resulted in a seamless transfer from a safety, health and environmental perspective.

As construction of our Horizon Project will involve a peak workforce of more than 4,000, we are focused on the development and communication of a consistent and well defined plan for health and safety management.

An ongoing priority for both our North American and International operations is the proactive involvement of our contractors in safety initiatives and their full participation in our safety management systems. All areas hold general contractor safety meetings, and as a result we have seen an increase in communications and a decrease in incidents. The exceptional performance at the Baobab fabrication and manufacturing facilities is an example of such positive results. With representation of our International safety personnel at the contractors' facilities, the main Floating Production, Storage and Offloading ("FPSO") vessels yard in Singapore achieved two million man hours without a Lost Time Injury.

Total North American natural gas vented per annual production (%)






Community: building and maintaining co-operative relationships

In 2004, Canadian Natural continued to build and maintain co-operative working relationships with our stakeholders. Our aim is to recognize stakeholder interests in our business and to listen and respond to them. We are integrating economic, environmental, and social considerations in the decision making process across all of our business activities.

In 2004 we built on our ongoing consultation program in the vicinity of our Primrose operations by initiating dialogue on our proposed expansion and the related Environmental Impact Assessment studies. Our Primrose operations are also an example of how we are incorporating Aboriginal traditional environmental knowledge to mitigate environmental impacts and to assist us in activities such as reclamation.

More than ever, residents, landowners, and key stakeholders are taking an active interest in the petroleum industry and multi-stakeholder initiatives and groups that are developing in many regions. We are playing an active role in such initiatives and are participating in synergy groups such as the Lakeland Industry Community Association and the Calumet Synergy Group. Through our Horizon Project we also actively participate on numerous multi-stakeholder groups including the Regional Aquatics Working Group, the Cumulative Environmental Management Association, and the Wood Buffalo Environmental Association.

An ongoing focus of Canadian Natural is to assist the members of the over 50 Aboriginal communities in which we operate to play a more direct role in the development of hydrocarbon resources and to realize social and economic benefits. In 2004, as part of our new contracting process, we pre-qualified approximately 200 Aboriginal businesses.

Building the capacity of communities to meet industry workforce demands and helping community members take part in employment opportunities available in the industry are an important aspect of our community engagement activities. For example, a priority is to provide employment and career opportunities for local and regional people on our Horizon Oil Sands Project. To this end we are playing an active role in Aboriginal skill development by participating and collaborating on numerous programs, among them the Alberta Aboriginal Apprenticeship Project and the Aboriginal Student Employment Program. We are also active supporters of Keyano College and other education, training and apprenticeship initiatives in the Wood Buffalo Region.

In northeastern British Columbia we are working with other producers on the Aboriginal Stay-in-School Program, and throughout our western Canadian operations we support Petroleum Education Training (PET) and other targeted industry programs. Additionally, our Building Futures Training and Education Program has gathered tremendous momentum and is entering its fourth year of operation.

Canadian Natural also invests time, energy, and funds in other ways to build stronger communities. Highlights of our community investments in 2004 included broad based employee and corporate support for the Calgary and area United Way Campaign, Alberta Children's Hospital Foundation and the University of Alberta with funding for Allan P. Markin/ Canadian Natural Resources Limited Natural Resources Engineering Facility. Donation toward the construction of the Bonnyville Centennial Centre, funding for the Cold Lake First Nation Day Care Centre and a donation toward the Keyano College Foundation Regional Municipality Sport and Wellness Centre in Fort McMurray represent other highlights.

The most significant areas of community support by our International Operations are centred in Côte d'Ivoire. Canadian Natural continued to support community projects focused on improving health and education facilities. As part of this program, Canadian Natural contributed to projects relating to a pediatric hospital and a local community agricultural scheme.

Our vision

- We conduct all of our operations in a way that protects the health and safety of employees, contractors, the public and the environment.
- We work co-operatively and effectively with communities, government agencies and interested stakeholders to reduce potential impacts of our operations and maximize opportunities for economic participation locally and regionally.
- We are committed to a long-term presence in the communities where we operate. Our significant business activities contribute to the economics and quality of life in areas where we do business, as do our community investments.
- We work together with community and industry groups to ensure a better, sustainable energy industry.
- We integrate environmental and community planning with project design and implementation.


Our Team

Lonnie Abadier, Walday Abeda, Hazel Aberdein-Quirie, Michael J. Adams, Steve Adams, Steven J. Adams, James Agate, Jennifer Ahern, Garrisen Ailsby, John A. Aina, Fiona Jean Aitken, Sina Akinsanya, Joseph Albano, Chris P. Alderson, Andrew Alexander, Bruce Alexander, Gregory Alexander, Daniel Alfred, Elena Algazina, Selena M. Allan, Jill Allen, John P. Allen, Simon Allerton, William S. Allerton, Devin Allibone, Karen Almadi, Eva D. Almeida, Gordon Almond, Robert Almond, Jocelyn Alonso, Nelson Alook, Ulises Amador, Joann Aman, Clark Ambler, Donald Ames, Sylvia Anaka, Grayson Andersen, Troy Andersen, Bruce Anderson, Greg Anderson, Jeremy Anderson, Kelvin Anderson, Larry Anderson, Leonard Anderson, Murray Anderson, Perri Anderson, Richard Anderson, Tery Anderson, Valrie Anderson, Peter Andrekson, Dale Andres, Janet Andrew, Todd Andrews, Gloria Angeles, Sherley Angers, Brian Antoni, Rogerio B. Antonio, Kathy Antonishyn, Shelley Antonuk, Feliciana Araujo, Jim Archibald, John Argan, James Arkley, Darryl Armstrong, Randall Armstrong, Rob Armstrong, Jane Arnst, Niels C. Arveschoug, Jim Asmus, Jacqueline N'Goran Asso, Sialla Victoire Assohou, Maguy Aude Atheba, Clifford Atkinson, John Atkinson, Nicole Atkinson, Gordon Au, Jason Auch, Bernard Auger, Marvin Auger, Richard Augustyn, Colin N. Avison, Eustace Azim, Cherine Badwi, August Baier, Dave Baier, Janice Baik, Michael Baik, Dwayne Bailer, Rod Bailer, Judy Bailey, Fatou Bakayoko, Chris Baker, Patricia Bakker, Reginald Baldock, Christopher Baldwin, David Baldwin, Mark Baldwin, Vaughn Baldwin, Joel Balkam, Gary Ballas, Ronnie Ballas, Sheldon Ballas, Mamadou Bamba, Darwin Banash, Bob Banks, Teresa Banny, Inge Bantli, Tammy Barclay, Tammy Barclay, Garry Bardoel, Larry Bardoel, Pamala Bare, Sharon Barker, Stephen Barker, Michael Barnes, Beverley Barnouw, Javier Baroja, Kenneth Barrett, Phrona Lisa Barrett, Melody Barrow, Marty Bartman, Sonia Basati, Lisa Bateman, Brenda Battyanie, Kevin Bauman, Juan Bavaresco, Veronica Bayley, Colin Beaman, Aura Beattie, Laurier Beaunoyer, David Bechtel, Chris Becker, Elke Becker, Gurpreet Bedi, Ewan Beenham, Behshid Behzadi, Guy Belanger, Lesley Belcourt, Betty Belenky, David P. Bell, Faye Bell, Jon Bell, William D. Bell, Reg Bellanger, Remie Belmonte, Ahmed Bendahmane, DavidS. Bendrey, Shelly Bensmiller, James Bentley, Linda Beresh, Lorn Berg, William Berg, Doris Bergeron, Jeffrey Bergeson, David Berlinguette, Henry Berlinguette, Allan Bertram, Murray Bertsch, Jonathon Best, Norman Beunder, Bob Bezpalko, David Biagi, Marc Bickham, Jennifer Bidlake Schroeder, Corey Bieber, Douglas Bielech, Inge Biener, Bruce Bignell, Roman Bilobrowka, Henry Bilodeau, Robert P. Bilsland, Rhett Binding, Roger Bintz, Warren G. Birch, Tim Bird, Travis Bishop, Paula Bissell, Peter Bissell, Kevin Bjornstad, Adam Black, Chad Black, David Black, David L. Black, Jennifer Black, Kenneth Blackhall, Kerri Blackmore, Michael Blair, Deana Blais, David Blake, Evan Blake, Christopher Blatchly, Ellen Bloomfield, Robin Bly, Allan Boddy, Brad Bodnar, Dennis Boehmer, Michael Boer, Kent Boerrichter, Crystal Boersma, Darcy Boettger, Marty Boggust, Brent Boguslaw, Gordon Bohrson, Paul Boileau, Peter Boisvert, Michael Bolianatz, Greg Bolin, Shawn Bond, Marguerite Bonnet, Patricia Booklall, Dustin Booth, Melanie Booth, Jack Bootsman, Barry Borbely, Albert Bordeleau, Lynnette Borgland, Michael Born, Dallas Borowski, Jon Borstel, Greg Boshaw, Keith Bottriell, Suzanne Boudignon, Kari Bouillet, Daryl Bourque, Jim Bowers, Slade Bowers, Dale Boychuk, Jeffrey Boyd, Patrick Boyd, Randy Boyd, Charline Boyer, Neil Bozak, John Brabec, Dave Bracey, Bryan Bradley, Peggy Bradner, Jan Bradshaw, Janet Bradshaw, Marianne Brady, Mary Jane Brady, Linda Bragg, Eleanor Branagh, Ralph Brand, Myron Brataschuk, Brad Braun, Colin Brausen, Vincent Breaker, Tara Brechin, Tara M. Brechin, Sharon Breitkreuz, Joseph Breland, Paul Breland, Roxane Bretzlaff, Robert Brisson, Shawn Brockhoff, Kelly Broda, Brian Brodbin, Ashley Broderick, Dwayne Brodziak, John Brogly, Bill Bromling, Murray Brooker, Dennis Brooks, Bill Brown, Carla Brown, Darren Brown, Julie Brown, Steve Brown, Robert Brownless, Elizabeth Brownrigg, Stewart R. Buchan, William D. Buchan, Anna Bucior, Linda Bucke, Natasha Buckland, Gordon Buckshaw, Linda Buczkowski, Malcolm E. Budd, Raymon Bueckert, Ryan Bulger, Clarence Bur, Trevor Burchenski, Melissa Burdan, Jeffrey Burdett, Heather Bureau, Keith Bureau, Grant Burgess, Crystal Burke, Gayle Burnett, Gerald Burtch, Corinne Burton, Rosemary Bussi, Jim Butler, Bob Butterworth, Ronald Butts, Leanne Butz, Tricia Butz, Todd Bymoen, Mike Byrtus, Irina Byvald, Mark Cadman, Mark S. Cadman, James Cadrain, Simon Cains, Simon R. Cains, Laura Calder, Laura Calder, Leslie Calder, Patrick Caldwell, Thomas J. Callaghan, Richard E. Calliou, Lynn Callsen, Lorraine Cameron, Mike Cameron, Tyson Cameron, Clayton Campbell, Dean Campbell, Doug Campbell, Earl Campbell, Nancy Campbell, Robert Campbell, Robert J. Campbell, Valerie C. Campbell, Andre Campeau, Ignacio Canapi, Gregory Cane, James M. Capjack, John Capstick, Kathleen Carbury, Fred Cardinal, Harley Cardinal, Sharon Cardinal, Wayne Cardinal, Jim Carey, Mary-Ann Carey, Ian Carleton, Leslie Carlyle-Ebert, Albert Caron, Murrey W. Carpendale, Kim B. Carrol, Gary Case, Mary-Jo Case, Trevor Cassidy, Mike Catley, Steve Caven, Susan Cervania, Samuel Cervantes, Ernest Chachula, Sachi Chakravarty, Joe Chamberlain, Cynthia Chambers, Katrina Chambers, Lise Champagne, Alan Chan, Jack Chan, Jik Chan, Sarah Chan, Tim Chan, Calvin Chapman, Melody Chapman, Todd Chapman, Deon Chappell, Darryl Charabin, Cynthia Chartrand, Leon Chateauneuf, Siddique Chaudhry, Dawn Chau-Lam, Gary Chaulk, Jackson Chaves, Jacinto Cheng, Mike Chernichen, James Cheung, Sherry Chiang, Gloria Chick, Patricia Childs, Sharon Chin, Jamie Chisholm, William Chiverton, Randall Chodzicki, Jessica Choi, Raymond Chong, Wayne Chorney, Lynn Chotowetz, Kin Chow, Sherry Chow, Daryl Chrapko, Alphonse Chretien, Ruth Christensen, Marianne Christianson, Steven Christie, Andy Chu, John Chuiko, Sharon Chung, Heather Church, Ronni Church, Sonja Chycoski, Kadidiatou Cisse, Magda-Christina Ciulavu, William Clapperton, Amanda C. Clark, Andrea M. Clark, Evan Clark, Evan M. Clarke, Martha Clarke, Olivia Clarke, Sanja Clarke, Walter Clarkson, Greg Clegg, George Clutton, Dale Coburn, Judith Cochran, Anna Cochrane, Sabrina Colangelo, Martin Cole, Elva Coley, Curtis S Collins, Rod Collins, Royston P. Collison, Chris J. Conway, Sean Conway, Brad Cook, Bill Cooke, Gary Coombe, Kent Cooper, Tammy Cooper, Jean Corbiere, Elaine Coreman, Linda Cormier, Rosetta Cormier, James Corner, Lorenzo Cortes, Neil Cortmann, Neil Cortmann, Harry Costello, Neil P. Costeloe, Wayne F. Cote, Juan W. Cottier, Douglas Coull, Douglas J. Coull, Jack Courchene, Kathryn Courtney, Dave A. Cousins, DavidH. Cousins, James Coutts, Gordon Coveney, Richard N. Coward, Keith Cowger, Catherine R. Cowie, Jonathan Cox, Myles R. Cox, Randy Cox, Wade R. Cox, Nigel E. Crabb, Harry Crabtree, Layne Craig, Ryan Craig, Bruce Crain, Bryan Crawford, Paul Crawford, Beverley Creed, Donald Cretney, Roger Crichton, David Cridland, Stefan Croft-Bednarski, Stefan J. Croft-Bednarski, Christopher Cross, Lana Cross, Lloyd Cross, Kirby Crowell, Anthony Csabay, Will Csanyi, Corinna Culler, Francesca Cultrera, Arley Currie, Brent E. Curtis, Dale S. Cusack, Kenneth Cusack, Pat Cusack, Real Cusson, Ken Cyr, Andre C. Da Costa, Helder J. Da Silva, Ivone Elma Malaquias Da Silva, Victor Daboin, Greg Dacyk, Fakhri Dadashov, Duane Dahl, Gary Dahl, Hamid Dahmani, Eliane Dakaud, Trevor D. Dales, Layne Dalgetty-Rouse, Walter M. Danchak, Aniko Dani, Gene Danyluk, Peter Danyluk, Eric Dargis, Lynne Darlington, Wigo B. Dascalescu, Graham K. Davidson, Marie L. Davidson, Philip Davidson, Tim Davidson, Todd Davidson, Frank Davis, Frank H. Davis, Graham Davis, Graham Davis, Randall Davis, Robert Davis, Sarah Davis, Jeffrey Davison, Peter G. Davison, Leonard Dawe, Robert Day, Ryan De Bruyne, Phil De Gagne, Daphne de Groot, Eric de Kock, Lance V. de Meillon, David Dean, Harry Dean, William E. Dean, Derek Dechaine, Raymond Dechaine, Roland Dechesne, Sheldon DeFord, Mervin J. Degenstien, Barbara Deglow, Daniel L. Deiana, Bonnie Deis, Gabriel Deliu, Franco Dell'Ovo, Benita DeLorenzo, Brent Delorme, Michael Delorme, Fiona Dempster, Fiona M. Dempster, Susan Dennis, Edward Deren, Tom Dereniwski, Semir Dervovic, Travis Desilets, Michael DesRoches, Laurie A. Devey, Wendy DeVisser, Robert Dewis, Karen Deyaegher, Vikas Dhawan, Aldo Di Flumeri, Karim Mounian Diallo, Harry Diamantopoulos, Sumara Diaz, Daniel Diaz-De-Leon, Catherine Dicken, Garry Dickie, Cameron Dickson, Sue Didyk, Irene Dikau, Anne Dillon, Michael Dingley, Ronald Dinkel, Hubert Dinn, Issiaka Diomande, Gayle Dionne, Al Dixon, Kathleen Dixon, Denise Dixson, Angela Dobb, Shawn Doble, John Dodman, Erin Doepker, Kelly Doepker, Ritchie Doering, Conrad Dombowsky, Kelly Dombrosky, Manuel P. Domingos, Dan Domke, Scott Donaldson, Minh Dong, Tim Donkersloot, Veronica Dooling, Tim Dootka, James G. Doran, AllenM Dorey, Cecil Dorey, Real Doucet, Edward W. Douglas, Dahl Dow, Angela Dowd, Wayne Draper, Colleen Drury, John Drury, Steven J. Drysdall, Calvin Duane, Laurie Dube, Albert Duczek, Jon Dudley, Rhonda Dudley, Liz Duerholt, Richard Duff, Simon Dugdale, Douglas Duguid, Albert Duhaime, Cheryl Dumais, Wayne Dumont, Barry Duncan, Craig Duncan, Craig Duncan, Lois Duncan, Sean Duncan, Graham M. Dunlop, Jill Dunlop, Robert Dunn, Lyle Dupuis, Dariela Duran, Harvey Dutchak, Diane M. Duthie, David M. Dutton, Eugene A. Dyjur, Krzysztof Dzwonek, Gary Earl, Kevin Earle, Julie Easthope, Suzanne Eaton, Sean Ebert, Jim Eby, Greg Ecker, James Edens, Robert Edgar, Josephine Angie Edoukou, Gordon W. Edward, Dave Edwards, Susan G. Edwards, Cindy Egden, Warren Eichhorst, Nicole Eitzen, Devin Ekdahl, Carole Eliuk, Anthony M. Ell, Mohamed El-Naas, Jerry Enders, Rommel Engler, Joanne English, Quentin Enns, Terry Erickson, Kresten Eriksen, Kent Erker, Polina Ersh, Sheldon Espetveidt, Rick Estrada, Lee Evans, Lee Evans, Rhonda Evans, Tim Evans, Leila Eveleigh, Maureen Evers-Dakers, Clayton Eves, Adrian R. Ewasiuk, Laura Ewen, Michael P. Eynon, Leonard Fabes, Lawrence Facchina, Denis Fagnan, Heather Fahey, Catherine Falconer, Andy Fankhauser, Travis Farrer, Ravinder Farwaha, Stefa Fassina, Arthur Faucher, John Fay, Karman Fayant, Tanya Fayant, Brian Fehr, Ira C. Feland, Maria H. Felix, Kurt Fenrich, Ken Ference, Tony Ference, Brad Ferguson, Helen Ferguson, Mark Ferguson, Roy W. Ferguson, Scott Ferguson, Mario Feria-Estrada, Joaquim Fernandes, Magdalena Ficek, Darren Fichter, Alan Fiddes, Michael Filipchuk, Neil A. Findlay, Kelly Finigan, Chad Finnebraaten, Tanya Fir, John Fisera, Calvin Fisher, David Fittkau, Rod G. Fitzpatrick, Sandra Fitzpatrick, Deborah S. Flanagan, Paul Flanders, Ken Fleck, Sean Fleming, Rodney Flett, Trevor Flood, Mark Flynn, Edmond Foisy, Justin Foisy, Ryan Folkerts, Gregory Fontaine, Robert Fontaine, Lynn Foo, Harris Foote, Adele Forcade, Curtis Formanek, Randy Formanek, Devon N. Fornwald, Alastair Forsyth, Alstair Forsyth, Gilles Fortin, Dwayne Fotty, Kevin Foulds, Lise Fournier, Neil M. Fowler, Peter Fowler, Donald Fox, Donna Frame, Joao A. Francisco, Ron Frank, Shelley Franssen, Gail Fraser, William J. Fraser, Barry Frazer, Ken Frazer, Ted Frederickson, Tammy J. Fremont, Roger Frere, Kurt A. Freyman, Brad Friesen, David Friesen, Kenneth Friesen, Andrei Frizorguer, Susan Froehlich, Frank Frosini, Scott Froude, Jennifer Fu, Karen Fujimoto, Curtis Fuller, Jim Fung, Ted Furuya, Josephine Gaddi, Leonard Gadowski, Sharon Gaehring, Kelly Gagne, Scott Gair, Larry Galea, Ron Gall, Michael Gallon, A. William Galloway, Yoko Galvin, Carlos Garcia, Doug Gardner, Jon Gareau, Glen Garton, Stan Garwon, Roger Gauchier, Joseph Gaugler, Maurice Gauthier, Steve Gavronsky, Melanie Gaw, Rafael Gay-De-montella, Paul Gazzard, Alain Gbo, Michael Geldert, David Geleta, Lesley-Ann Gemmell, Patricia Gentles, William George, James Georget, Matthew Gering, Michel Germain, Raymond Germain, Robert Germain, Sandra Germaniuk, Albert Gervais, Paul Gervais, Sheldon Getson, Beryl Gettings, Clark Getz, Ken Getzinger, Zoheir Ghaddar, Douglas Gibson, Charles Giddings, Jean Giesbrecht, Jerry Giesbrecht, Dwayne Giggs, Laura Giggs, Elias Gildeh, Tamara Giles, Ralph Gill, Jeremy Gillespie, John S. Gillespie, Sharen Gillett, Janna Gillick, Sandra Gillis, Justin Gilmour, Justin S. Gilmour, Douglas Ginn, Stewart Girbav, Nadine Giroux, Ben Gisby, Marvin Gladue, Russell Gleed, John Glennon, James Glessing, Peter Goetz, David Golden, Brian Gonsalves, Yvonne Gonzalez, Ian Gordon, James Gordon, Wendy Gordon, Winston Goretsky, Yvon Gosselin, Allan Gould, Todd Gould, Antonella Goulet, Sandra Goundrey, Carl Graham, Jacqui Grant, Allissa Gray, David Gray, Ronald Gray, John Greaves, Linda Green-Bowen, Theresa Greene, Lisa Greenhall, Ernie Greenwood, Lisa Gregg, Derek Greidanus, Clint Greschner, Edmond Griffiths, Leo Groenewoud, Wayne R. Gruhlke, Neil Guay, Trevor Guay, Cesar Guercio, DonL Guglielmin, Gilbert Guigon, Robert Gullion, Shane Gullion, Swarna Gunaratne, Carolyn Gunderson, Alan Gunst, Edward Gushnowski, Terry Gusnowski, Elaine Gussman, Graham Gustafson, Bartley Haahr, Violet Haddad, Resad Hadzismajlovic, Keri Hageman, Keri Hagemann, Egbert Hagens, Chad Hagstrom, Keith Hague, Sam Hajar, Shemin Haji, Dan Halaburda, Montie Hale, Dean Halewich, Rick Halkow, Donald Hall, Kathy Hall, Todd Halladay, James Hallett, Robert D. Hallett, Frank Halliday, Larry Hamende, Jeremy Hamilton, Tim Hamilton, Kevin Hamm, Michael Hammel, Rick Hammond, Elaine Hampton, Brad Hancock, Anne Hand, Carol Handley, Carol F. Handley, Dave Handy, Karl Hann, James Hansen, Ole Hansen, Darcy Hanson, Judy Hanson, Brent Harbin, Leon Harder, Kent Hardisty, Liam Hare, Liam L. Hare, Ken Harke, Brent Harle, Leslie C. Harley, Angela Harlos, Stan J. Harney, Erik HaroldsonChad Harris, Jody L. Harris, Roger Harris, Stephen Harris, Randy Harsany, Lisa Hartman-Thair, James Harty, Mike Harty, Jerry Harvey, Julie Harvey, Julie A. Harvey, Cory Harvie, Cheryl Hasenclever, Colin C. Hastings, Iain Haston, James I. Haston, Ewen P. Hatchwell, Bryan Hattebuhr, Christine Hattebuhr, Dale Hattebuhr, Helen Hattie, Barret Hatton, Wayne Hatton, Dave Haub, Dave Haub, Willow Hauber, Wayne Hausch, Lew Hayes, R. Joey Hayward, David M. Haywood, Sean Head, Jay Heagy, Larry Heath, Brian Hebert, Terry Heck, Ken Hedstrom, Sherrie Heil, Robin Hein, Raymond Heisz, Mahmud Hejni, Mahmud Hejni, Barton Henderson, John Hennessy, Anita Hennig, Leona Hennig, Jackueline Herauf, Kim K. Herbst, Sheri Herman, Judith Hermann, Darryl E. Herner, Luis Herrera, Keith Heslop, Keith Heslop, Matthew Higgins, Rachelle Higgins, Tyla Higgs, Charlene Hill, Gordon Hill, Marie Ellen Hill, Steve Hill, Jesse Hillebrand, Laureen Hillebrand, Christie Hillis, Arnold Himschoot, James Hinde, Jim Hlewka, Margaret Ho, Barry Hodgan, Gary Hodge, Barbara Hofer, Kevin Hogg, Krista Hogg, Kevin Hoium, Doug Holman, Richard Holman, Donald Holmen, Ian Holmes, David Holt, Kim Holtby-York, Shannon Hood, Corey D. Hooge, Hans Hoogendam, Blaine Hook, Keith Hornseth, Camelia Horvath, Lance Hoskyn, Tom Hougen, Sherri Houle, John Howard, Kim Hranac, Joanne Huang, Barry Hucik, Paul Hudson, Jeremy Hughes, Mark Hughes, Bryan Huk, Riley Hull, Terry Humbke, Kevin Hunter, Robert A. Hunter, Tom Hunter, James Hurdal, Bradley Hurtubise, Glenn Hussey, Cody Hutchinson, Myrna Hutchinson, Ray Hutscal, Bruce J. Hutt, Greg Huva, Donald G. Huxley, Stephen Hygard, Scott Hyrcha, Matthew Ilchuk, Detlev Imorde, Dominic Ing, Michael Ingles, Brad Inman, Jamieson J. Irons, Jeff Irons, Darren Isele, Floyd Isley, Karen Ivan, Jeff Iwanaka, Nicholas A. Jack, Wallace Jack, Daniel Jackson, Judy Jackson, Kevin Jackson, Victoria Jackson, Ken Jacobs, Ken Jacobson, Albert Jacula, Curtis Jacula, Irene Jacula, Todd Jacula, Hamid Jafari, Vivek Jain, Annie Jalotjot, Chris James, Bob Jamieson, Maria Jancewicz, Steve Jansky, Peter Janson, Leonard Janzen, Nancy Jarman, Calvin Jarratt, Mark Jean, Wendal M. Jellison, Megan Jenkins, Jason Jenner, Lindsay Jenner, Kevin Jensen, Parry Jensen, Qi Jiang, Agostinho Joao, Terry Jocksch, Amy Johnson, David Johnson, Evan Johnson, Jeffrey Johnson, Leslie Johnson, Mitzi Johnson, Neville Johnson, Stacy Johnson, Susan Johnson, Joe Johnston, Victoria Jolliffe, Brent Jones, Delbert Jones, Ian Jones, Lori Jones, Mark A. Jones, Pamela Jones, Susan Jones, Tracy Jones, Damian Jordan, Joy Joseph, James Jung, Chris Jungen, James Jurome, Paul Kabatek, Asif Kachra, Carol Kadutski, Raymond Kahanyshyn, Myra Kalakailo, Derek Kalynchuk, Shari Kane, Harwinder Kang, Nashila Kanji, Stephanie J. Kape, Sam Kapoor, Dwayne Kaprowski, Brad Karaja, Angela Karst, Doug Kary, Lynn Kasper, Shelina Kassam, Martin Kasserra, Myles Kathan, Deanne Katnick, Christopher Kean, David Keck, Philip Keele, Christopher Keim, John Keith, Chuck Keller, Christine Kelly, Simon Kelsey, Simon Kelsey, Denise Kennedy, Julian Kennedy, Julian P. Kennedy, Wayne Kennedy, Val Kenyon, Angela Kerr, Angela Kerr, Blair Kessler, Lori Ketchuk, Tatiana Kharitonova, Kimberly Kielt, Leonard Kiez, Iain Kilpatrick, Selma Kilpatrick, Curtis Kimler, Stan Kimmie, Douglas King, Kurt King, Richard King, Richard King, Richard King, Richard G. King, Peter Kinnear, Cam Kinniburgh, Marvin Kinsman, Sandra Kintzl, Anthony Kirtley, Anthony F. Kirtley, Gord Kirwan, Cryssy Kish, Brent Kissel, Robyn Kissel, Shane Kissel, Marlene Kissoon, Mario Kiteculo, Bob Kitsch, Cody Klatt, Dalton D. Klippert, Jeff Knibbs, Allen Knight, Anita Knipe, Patricia Knipe, Ernest R. Knowles, AJohn Knutson, Russ Kobi, Corey Koble, Barney Kobzey, Kouakou Laussin Emma Koffi, Blair Koizumi, Lutz Kolberg, Eva Komers, Cameron Komm, Brent Kondratowicz, Ibrahim Kone, Jennifer Koslowski, Diane Kostiuk, Ann Kostyshyn, Stacey Kotelniski, Didier Kouame, Hermann Didier Koffi Kouame, Richard Kowalski, Kevin Kowbel, James S Kowula, Dennis Kozak, Teresa Kozina, Dale Kozma, Cameron Kramer, Andrew Krancz, Lyndon Krankowsky, Trevor Kratz, Mike Kraus, Bryan Krause, Trevor Krause, Todd M. Kreics, Jeffrey Kreiser, Patti Krekoski, Michael Krips, Peter Krol, Gabriel Krywolt, Chris Kubisch, George Kucy, Warren Kuefler, Vikas Kumar, Len Kurowski, Frank Kurucz, Daisy H. Kwan, Don Kwan, Kelly Kwiatkowski, Angele Kwon, Bob Kyllo, Jocelan Ladner, Philip Lafond, Levi Lafrance, Ronald LaFrance, Cassandra Lai, Ronald Laing, June Lajoie, Edward G. Lalande, Mahmud Lalani, Melaine Lam, Susan Lamb, Richard Lameman, Michel Landry, Francis Aaron Lane, Robert F. Lang, John Langille, Carolyn Langpap, Michelle Lapointe, Pamela Lapp, Melvin Lapratt, Leon LaRose, Ozlem Larsen, Dave Larsh, Rob Larson, Ronald Lasek, Reno Laseur, John Lasocki, Daniel Lastiwka, William Latchuk, Glenda Latham, Joan Latter, Krista Latunski, Laura Latyn, Robert Lauder, Robert Lauder, Karen Laurin, Steve Laut, Bernard Lavoie, Iris Law, Joanne R. Law, Lucas K. Law, Darron D. Lawrence, Ewen J. Lawrence, Fred Lawrence, Brian W. Lawson, Martin W. Lawson, David Laycock, Chelsea Layden, Sharon Layton, Greg Lazaruk, Brian Leach, Doug Leach, Albin Leaf, Amanda Leam, Margo Lebel, Rodney Leblanc, Amanda Lee, Carmen Lee, Colleen Lee, Fernando Lee, Jane Lee, Swee Lee, Tim Lee, David Leeper, Kevin Legault, Kris Lehocky, Gustavo Leon, Joseph Leonard, Gary Leong, Stephen Lepp, David Lesko, Gerry L. Leslie, Marcus J. Lethaby, Phil Letkeman, Don Leung, Esther Leung, Katie Leung, Preeminence Leung, Maurice Levac, Tracy Levasseur, Jean Levesque, Shelly Lewchuk, Susan Lewis, Katherine Leys, Larry L'Hirondelle, Jun Li, Craig Liba, Suzanne Lin, Bonnie Lind, Katherine Linder, Janette Lindsay, Shari Lindsay, Trina Lineger, Janice Linehan, Annette Linggon, Yvonne Linnartz, Yuri Lipkov, Jennifer Little, Jennifer Little, Tracy A. Little, Tony Littlefair, Dennis Liu, James Livingston, Michael R. Livingstone, Cam Lizee, Dale Lloyd, Dale Lloyd, Debby Lo, Conrad Loch, Richard Lock, Fred Locke, Kendall Locke, Darren Loder, Joy Lofendale, Per Lofgren, Shauna Logan, Randal Logelin, Rodney Logozar, Craig Long, Wade Longmore, Herb Longworth, Nelson Lord, Darin Lorenson, Bob Lorinczy, Nancy Lotocki, Michelle Lou, Andrew B. Lough, Larry Love, Cheryl Lovelace, Dan Lowe, Darryl Lowe, Devin Lowe, Brad Lowell, Leah Loyola, Gerd Lucas, Serena Lucci, Dana Lund, Wes Lundell, Paige Luong, Jason Lush, Rees Lusk, Wendy Lutzen-Askew, Brent Lydiatt, Kathy M. Lydiatt, Ken Lynam, Joseph Lyttle, Nicky Maawia, Patricia MacCrimmon, Lindsey R. Macdearmid, Jason MacDonald, Ray MacDonald, Stephen MacDougall, Carl Machin, Shawn Mack, Graeme P. MacKenzie, Ken MacKenzie, Ryan MacKenzie, Shawn MacKenzie, James William MacKinnon,

Number of Canadian Natural employees

04	2,597
03	1,809
02	1,448
01	1,080

Jesse A. MacKinnon, Joseph M. MacKinnon, Graham K. Mackintosh, Richard MacKnight, Mark MacLean, Susan MacLean, Douglas MacLeod, Jamie MacLeod, E. Anne MacNeil, Bradley MacNeill, Joanne MacNicol, Angela J. MacNiven, Marilyn Macoy, Heidi A. Macrae, Bruce Maddex, Morgan Maddison, Gary D. Madsen, Markus Maennchen, Mike Magnusson, Bill Mah, Jennifer Mah, Tony Mah, Joey Majerech, Anita Mak, Darren Mak, John P. Malachowski, Ronald Malboeuf, Linda Maloney, Mike Manchen, Leonard Mandrusiak, Darcy Mandziak, Darcy Mann, Don Mann, Ronald Mann, Rachelle Mantei, Jun Manzano, Roy Marceniuk, Ronald Marcichiw, Nicholas W. Margiotta, Shane Marion, Allan Markin, Luis Marquez, Andrew Marsh, Chris Marshall, Lynn Marshall, Mary Marshall, Sally Marshall, Karen Martin, Lindsay Martin, Tracy Martinka, Dave Marttila, Mike Masse, Al Massicotte, Davinder Mathur, Scott Matieshin, Tim Maxwell, Richard May, John Mayall, Edward Mayer, Lyle Mayer, Scott Mayer, Scott R.G. McAllister, David R. McBride, PatL McCarron, Robert McCormick, John McCoshen, Clete McCoy, Erin McCoy, Ken McDavid, Cynthia McDonald, Kevin McDonald, Laurie McEwen, K. Tracy McFadyen, Debra McFarlane, Frances McGlynn, Grant McGowan, Robert McGowan, Ryan McGowan, Bruce E. McGrath, Paul McGroarty, Tom McHale, Eric A. McIntosh, Daniel McKain, Kim I. McKay, Lindsey McKay, Rod McKay, Tim McKay, Keith McKenzie, Kenneth G. McKenzie, Michael Mckenzie, Mike McKenzie, Douglas McLachlan, Bonnie-Lynn McLaren, Marla McLean, Michelle McLean, Joan McLellan, Ron McMahon, Blake McManus, Sandra McMichael, David McNamara, Kendal McNeil, Lynn McNeil, Bill McNeill, Stephanie A. McNeill, Jaime McNichol, Elaine M. McPherson, Rick T. McQueen, Tracy McRae, Frank McVey, Wendy S. Measures, Karyn Meehan-Coles, Barry Meier, Daniel Meier, Monty Meikle, Darryl Mekechuk, Gloria Melenberg, Belinda Meller, Dick Mellor, Jean Melnychuk, Marvin Melnyk, Paul Mendes, Lynette Mercer, Lynn Mercer, Mark Mercer, Orville Mercer, Timothy Merk, Greg Merkel, Danny Merkley, Dwight Mervold, Steve Meunier, Cindy Michalko, Barry Michelson, Murray Michie, Ian Middler, Dale Midgley, Jacek Mielczarek, Marc Miiller, Jane Mikalsky, Jacqueline Miko, Guillermo Milan, Gary Miller, Jeffrey Miller, Wendy Miller, Bruce Mills, H. John Mills, Ronald Mills, Colin Milne, June E. Milne, Stephen J. Milne, Michelle Minick, Wyman Minni, Denis Mino, Kerry Minter, Carolyn Minton, Alan R. Minty, Maria-Celeste Miranda, Umar Mirza, Daleep Misri, Charlene Misurelli, Brent Mitchell, Yvonne B. Mitchell, Neven Mitchell-Banks, Anar Mitha, Leon Miura, Glen J. Mock, Tom Moen, Derek Moir, Rosa Moises, Lydia Mok, Mimi Mok, Dwayne Molle, Jelena Molnar, Roy Monro, Rick Monteith, Alfred Moon, Alfred Moon Jr, Judy Moore, Kevin Moore, Jason Moravec, Christopher Morgan, David Morgan, Karen Morgan, Marcia Morgan, Shaun Moroziuk, Karen Morrice, Karen Morrice, Paul H. Morris, Terry M. Morris, Tyler W. Morris, Louise A. Morrison, Joseph Morrow, Wesley N. Morrow, Paul Mossey, Glen Mott, Cheryl Mouta, Barbara Mowat, Wayne B. Mudryk, Jackie Mueller, Sieg Mueller, Colin W. Muir, Lee-Ann Mules, Lucy Mulgrew, Robert Mulholland, Kendra Muller, Noella Mulvena, Martin Munday, Cora Murphy, Dale Murray, Dean Murray, Deirdre M. Murray, Patricia E. Murray, Shara Murray, William K. Muss, Kevin D.J. Mutch, Lorna Myers, Melonie Myszczyszyn, Richard Nachtegaele, Aleksandra Naczk-Cameron, Ashley Nagy, Jeannine Nagy, John D. Naismith, Bill Nalder, Elly Nance, Rick Napier, Bill Navratil, Gita Nayak, Randy December, John E. Neff, Fikerte Neguisse, Eduardo Neira, Aaron Nelson, Douglas Nelson, Gilbert Nelson, Peter M. Nelson, Vincent Nelson, Brad Nessman, Monty Neudorf, Caleb Neufeld, Brian W. Neumeier, Melissa Neumeier, Dustin Newman, Jason Newman, John Newman, Kevin Newton, Alice Ng, Helen Ng, Eileen Ngo, Minh Nguyen, Tai Nguyen, Thu-Van Nguyen, Fawn L. Nichol, James Nicholson, Doris Nickel, Simon G. Nicol, Josie Nicolajsen, Jason Nielsen, Wayne Nielsen, Rod M. Nisi, Steven Niu, R. Scott Noble, David R. Noel, Geoff Noel, Greg Nolin, Trisha Nordquist, Robert Norman, Troy Normand, Kerry Novinger, Daniel Nugent, Eden Nunes-Vaz, Edward Nunes-Vaz, Kelvin Nurkowski, Robert Nuytten, Genia Nyenhuis, Wayne Nyholt, Tim Nyitrai, Jason Nykolaychuk, Donald Oaks, Pamela O'Brien, Charito Ocampo, Richard Odlin, Robert Ogilvie, Anne Marie O'Gorman, Kevin O'Hearn, Tammy Ohlhauser, Hugo Olaciregui, Alvin Olchowy, Delvin Olesen, Deanna Olichny, Scott Oliphant, Dianne Oliveira, Cathy Oliver, Jason G. Ollikka, Ghasem Oloumi, Richard Olsen, Dean T. Olson, Stephen Olson, Dave O'Neil, Steven P. O'Reardon, Flora O'Reilly, Doug Orlecki, Alison Orr, Colette Orr, Neil Orr, Colin Orton, Perry Osgood, Wayne Otteson, Denis Ouellette, Jolanta Ouellette, Jean Francois Ousset, James Overall, Mark Overwater, Mark A. Owen, Michael Owens, Peter A. Owens, Dennis Ozaruk, Fabio Pacheco, Rodney Pacholek, Ron Pacholuk, Jared Paddock, Larry Padley, Doug R. Page, Marcus Pagnucco, Robert Painchaud, Randall Paine, Elizabeth A. Palmer, Lee Palmer, Michael Palmer, Rick Palmer, Glenn Paluck, Jamie Pandachuck, NealE Pangman, Garry Pangracs, Beata Pankiw, Brian Pankiw, John Papp, Pat Paradis, Theo Paradis, Blair Parent, Bernard Parenteau, Clement Parenteau, Blaine Parker, Darby Parker, Herbert Lyle Parker, Steve Parker, Barry Parkin, Randy Parkyn, John Parr, John Parry, Ken Partsch, Lawrence Paslawski, Joey Pasos, Randy Passmore, Michael Pasveer, Judy Paterson, Judy Paterson, Brian Patterson, Donna Patton, Chris Paulette, Wilma Pauls-Atas, John Paulson, Brian Paulssen, Daniel Pavelick, Lance Pawlik, Rick Pay, David Payne, Dean Payne, Elaine Payne, Keith Payne, Gary Pearce, Gerald Pearson, Pam Pearson, Robert Pearson, Brenda Peatch, Hans H. Pedersen, Philip Pedersen, Shawn Pedersen, Brian Pederson, Lance Pederson, Dianne Peel, Sean Pell, Bruce C. Penner, Robin Penner, Kevin Pennington, Maria H. Victoria Pereira, John Perepelecta, Don Perry, Gladys Perry, Tarla Persaud, Bernie Persson, Bernard Peterson, Bill Peterson, Brenda Peterson, Douglas Peterson, Dino Petrakos, Rick Petrick, Henry Petrie, Henry Petrie, Rodney Petrie, Lucyna Pettigrew, Marie (Huong) Phan, Bryanne Philibert, Doug Pierce, Frank Pike, Ron Pilisko, Kathy Pinco, Dale Pinder, Gabrielle Plandowski, Ted Plouffe, Erwin Po, Imhotep Pocaterra, Hector Poirier, Donna Poitras, Wade W. Poitras, Brandy Poliakiwski, Marlene Pollock, Stuart Pollok, Stuart Pollok, Eleanor Polson, Robert Pool, Chris Poole, James Pope, Oksana Porteous, Carol Porter, Patti Postlewaite, Jeffrey Poth, Randy Pottle, Ryan Potts, Bruce Powell, Susan Powell, Laurie Power, David Pratt, Mike Preece, Lesley Proctor, Doug Proll, Sarah L. Proudlock, Jacques J. P. 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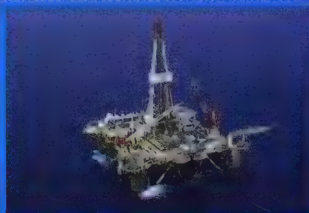
Global Operations

We have solid platforms for continued profitable growth.



We dominate the land base and control the infrastructure.

An exploitation approach reduces overall risks and helps control costs.

Continued disciplined delivery will result in a strong, organic growth profile.

North America

	2004 results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Oil and NGLs	180	648
Natural gas	175	432
Boe	355	1,080
% of total	81	71

Essential elements of our strategy

- Allocate capital to maximize returns.
- Maintain defined growth, value enhancement plans for each of our products and basins.
- Maintain balance in:
  - Product mix;
  - Project time horizons;
  - Acquisition/exploration with focus on exploitation; and,
  - Financing sources and maturity profile.
- Complete opportunistic major acquisitions.
- Control costs through area knowledge and domination of core focus regions.

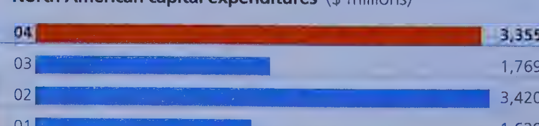
North America

We have an exceptionally strong natural gas asset base including two of the most prospective natural gas growth regions in western Canada. Our defined growth plan will provide 5% per annum natural gas growth without sacrificing our economic principles.

Our existing light oil asset base provides the Company with excellent opportunities for reserves growth through application of secondary and tertiary recovery schemes. At Pelican Lake we have a massive resource where waterflood development is increasing oil recovery with further improvements possible through polymer flooding.

With almost three billion barrels of heavy oil resources, a defined growth plan and the opportunity for additional heavy oil markets, we will deliver continued growth from both primary and in-situ projects.

North American capital expenditures ($ millions)



North Sea

	2004 results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Crude oil and NGLs	65	303
Natural gas	8	5
Boe	73	308
% of total	17	20

Offshore West Africa

	2004 results, after royalties	
	Production (mboe/d)	Proved reserves (mmboe)
Crude oil and NGLs	11	115
Natural gas	1	12
Boe	12	127
% of total	2	9

North Sea

Since 2000 we have accumulated four operating hubs in the North Sea which we operate and control via large ownership positions.

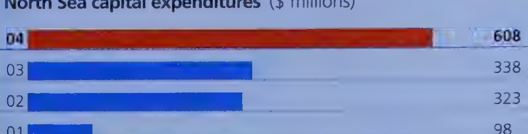
We have been able to leverage our exploitation core competencies in this recently mature basin. We believe that the region is very similar to western Canada in the 1990s where we built the Company through cost control, low-risk exploitation, opportunistic acquisitions and prudent exploration.

Offshore West Africa

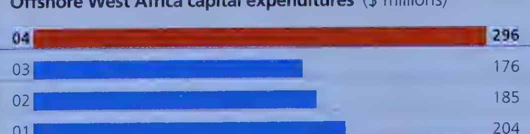
Currently, the vast majority of our activities are located in Côte d'Ivoire. Here we have been able to accumulate positions that enable us to dominate the infrastructure and landbase. Over the past three years we have been able to lever the exploitation of the Espoir Fields into a successful exploration program. The result of which is the Baobab Field which will commence production in 2005. We commenced 2002 with no production in Côte d'Ivoire and will exit 2006 at about 60 mboe/d of production - a significant achievement in a very short time.

We believe that additional exploration potential exists in Côte d'Ivoire and we continue to examine opportunities in other countries in the region.

North Sea capital expenditures ($ millions)



Offshore West Africa capital expenditures ($ millions)



Review of Assets

North American natural gas

North American natural gas is Canadian Natural's single largest product, representing 45% of our sales volumes and 46% of sales revenues. During 2004, average production volumes increased by 85 mmcf/d or seven percent, reflecting a strong drilling program and two strategic property acquisitions during the year. This production is concentrated in four of our North American core regions: Northeast British Columbia, Northwest Alberta, Northern Plains and Southern Plains.

We have a well articulated five year plan for each of our regions that will create five percent per annum growth in production volumes in a basin where most competitors are shrinking or struggling to remain flat. We also have the discipline to deliver that plan – our natural gas exploitation philosophy minimizes exploration risks, operating costs and capital costs:

- Maintain a large inventory of undeveloped land in each core region, enabling us to pre-plan our drilling program for the next five years in the most optimal manner.
- Dominate the land base and control the infrastructure in which we operate. We maintain high working interests and operate everything, enabling us to steward to our own agenda.
- Progressively develop lands as extensions from our facility infrastructure, thereby minimizing development costs and maximizing utilization.
- Continually challenge our own technical and operating paradigms and learn from our competitors to maintain and enhance our low cost advantage.
- Target geological areas with multi-zone drilling, yielding exceptionally high drilling success rates.
- Once onstream we manage our facilities to maximize throughput. Our compressor utilization ratios are among the highest in the industry, allowing us to reduce per-unit operating costs.

North American crude oil

Canadian Natural is one of Canada's largest producers of crude oil and NGLs with an extensive developed and undeveloped light and heavy crude oil asset base augmented by NGLs which are produced in conjunction with natural gas. During 2004, average production volumes increased by 7%, reflecting our successful drilling and development program and our strategic acquisitions. Our heavy crude oil production is concentrated in the Northern Plains core region with light crude oil being produced in all five core regions: Northeast British Columbia, Northwest Alberta, Northern Plains, Southern Plains and Southeast Saskatchewan.

Our defined plan for North American crude oil was developed in concert with our heavy crude oil marketing strategy. This disciplined plan develops our assets as market expansion warrants it. Our exploitation based philosophy capitalizes on our core region dominance to reduce capital and operating costs and the use of appropriate technologies to maximize recovery:

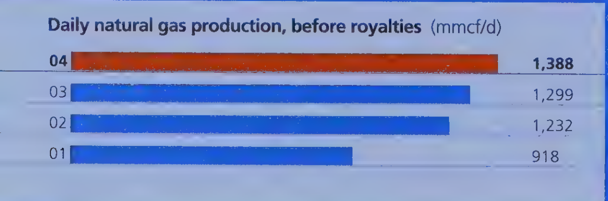
- Maintain a large inventory of undeveloped land in each core region, enabling us to pre-plan our drilling program for the next five years in the most optimal manner.
- Dominate the land base and control the infrastructure where we have assets. We maintain high working interests and operate everything, enabling us to steward our own agenda.
- Own and control key infrastructure to control costs. In the heavy oil business we control pipelines, oil batteries, and water and sand disposal facilities. The large scale of our operations allows us to optimize these facilities enabling us to maintain our low cost advantage.
- Continually evaluate new technologies and pilot the most promising to maximize resource recovery.

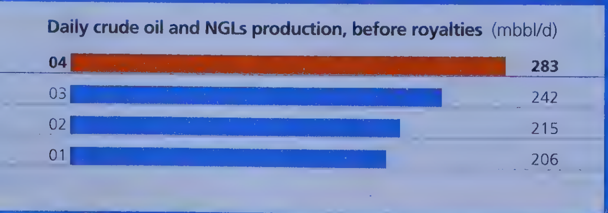
International crude oil

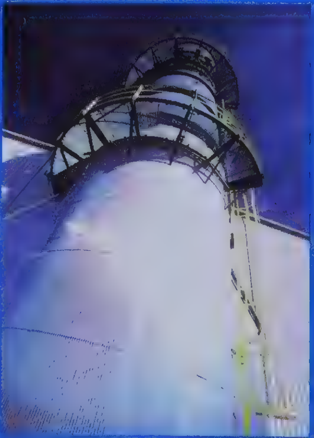
We view our International Operations as a vehicle for continued light crude oil production growth. A disciplined and focused approach is essential to successful value creation in the international arena. Therefore, we contain our exposure to those basins where we see the greatest opportunities and we can best lever our business strategies. We capitalize on our core competency of exploitation in the North Sea where the business parallels that of the WCSB in many key ways. Offshore West Africa provides significant exploration upside and capitalizes on strong government relationships developed over the past few years. In both basins, we operate in areas where we dominate the land base and infrastructure supporting our operations.

Horizon Project

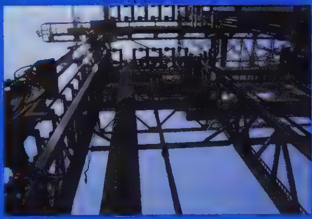
The Horizon Project is truly a world class project. Open pit mining and extraction operations will be complemented with an onsite upgrader to produce 232,000 bbl/d of light, sweet synthetic crude oil. As this is a mining development, production declines normally associated with oil and gas operations are avoided – creating a stable, reliable source of light crude production and cash flow for decades to come.







Jeffrey W. Wilson
Senior Vice-President,
Exploration



Acquisitions

In February 2004, we announced the acquisition of Canadian heavy crude oil resource properties for net consideration of $471 million. The net production acquired was approximately 28 mbbl/d of heavy crude oil resource properties and 9 mmcf/d of natural gas. This acquisition fit our strategy of dominating core regions and related infrastructure. Additionally, we were able to effect operating cost reductions through synergies with our own existing facilities and through use of the ECHO Pipeline. Approximately 300 new well locations and 400 well recompletion opportunities were identified on these assets. The acquisition complemented our heavy crude oil strategy by increasing our market share without increasing overall supply of heavy crude oil from Alberta.

In April 2004, we announced the acquisition of Canadian resource properties for consideration of $280 million. The properties were producing approximately 68 mmcf/d, before royalties, and contained over 415 thousand acres of developed and undeveloped land. The acquisition lands are characterized by large, undeveloped pools with significant natural gas potential in deeper zones and added a new exploration base in the Alberta Foothills, complementing our existing holdings.

In the third quarter, we acquired 16 mboe/d of light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests in the T-Block and B-Block, together with associated production facilities, including a fixed platform, FPV and an adjacent exploration acreage.

Finally, in November 2004, we announced the acquisition of resource properties for consideration of $703 million. The associated production was 105 mmcf/d of natural gas and 7.5 mbbl/d of light crude oil and NGLs. The acquisition also included over 510 thousand net acres of undeveloped land and added 90 new well locations and 200 well recompletion opportunities to project inventory. In addition, it added the light crude oil operating area of Dawson in our Northern Plains core region.

Natural gas – core region summary

	Northeast British Columbia	Northwest Alberta	Northern Plains	Southern Plains	International and other
Average production, before royalties (mmcf/d)					
2004	**437**	**303**	**430**	**156**	**62**
2003	372	261	462	142	62
Major natural gas facilities, operated	8	7	5	–	–

North American crude oil and NGLs – core region summary

	Northeast British Columbia	Northwest Alberta	Northern Plains	Southern Plains	Other
Average production, before royalties (mbbl/d)					
2004	**7**	**11**	**166**	**13**	**9**
2003	7	11	136	11	10
Major crude oil facilities, operated	1	–	9	–	–

International crude oil – core region summary

	Offshore West Africa	North Sea
Average production, before royalties (mbbl/d)		
2004	**12**	**65**
2003	10	57
Platforms/FPSOs, operated	2	8

North American Natural Gas

Northeast British Columbia

The asset

Our experience in the region, our large undeveloped land base of two million acres and vast pipeline infrastructure affords us a significant competitive advantage in this highly prospective region. This region has three areas of focus:

1. In the northern Helmet area, horizontal drilling exploits the low risk, regionally extensive, natural gas charged Jean Marie carbonate formation.
2. In the Fort St. John area, natural gas is produced from an array of carbonate and sandstone reservoirs ranging from the Notikewin at 2,000 ft to the Slave Point at 15,000 ft.
3. In the southern foothills area, we target thrusted Mississippian, Triassic, and Cretacious age reservoirs.

Exploitation

At Helmet, the Company drilled 52 wells with an 88% success rate, adding incremental production of greater than 40 mmcf/d. In the Ft. St. John block a total of 123 wells were drilled with a 92% success rate, including 86 Notikewin natural gas wells. Since this regional play was identified in late 2003, the Company has drilled 99 wells on this trend with a success rate of 92%. These high success rates are directly related to the lower risk exploitation approach outlined above.

Acquisitions

By levering our greater area knowledge and dominance we were able to close two acquisitions in 2004 that further strengthened our production and project inventory in Northeast British Columbia. Assets acquired in the second quarter added significant land holdings and production in the Ft. St. John area. We utilized our extensive knowledge of the undeveloped Notikewin and Gething natural gas plays to add value while adding complementary production to our existing Ladyfern operations. In the fourth quarter, we acquired additional assets that complemented our existing holdings in the Ft. St. John area. The major properties acquired contain multi-zone gas prospects that will reduce drilling risks. Multiple drilling and recompletion opportunities have been identified as a result of our extensive knowledge in the region.

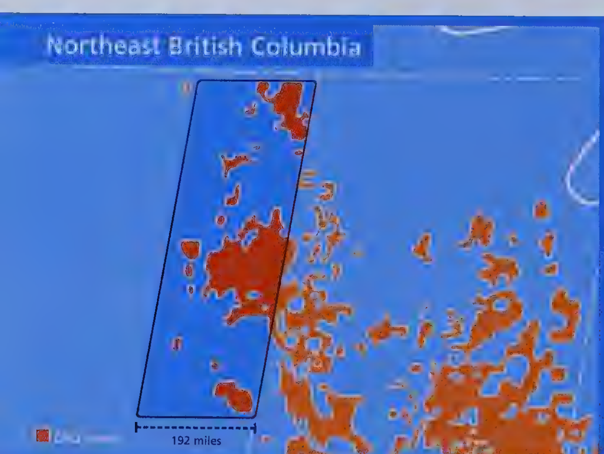
Exploration

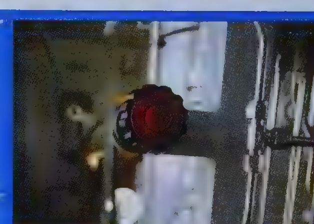
We apportion a small capital budget each year to explore for Slave Point pinnacle reefs with target sizes of 5 to 30 bcf. In 2004, two Slave Point wells were drilled resulting in one successful well. In the Foothills area we are increasing our focus in a measured way as we target Falher and Nikanassin reservoirs. Well costs are higher and pipeline infrastructure is often limited, but rates and reserves are commensurately much higher. During 2004, nine wells targeting deep reservoirs were drilled with a success rate of 83%.

What to expect in 2005 and beyond

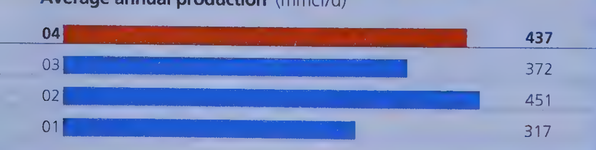
The 2005 drilling program continues with more than 200 wells planned, including 100 Notikewin wells and 50 horizontal wells at Helmet. On the exploration front, twelve deep natural gas wells are planned.

Our project inventory is deep with almost 1,300 well locations planned over the next five years. This includes 500 Notikewin wells, 275 Helmet wells and 60 deeper exploration targets in Ft. St. John and the Foothills. This deep inventory is one of the key drivers to our natural gas growth strategy. We anticipate resource potential of 1.2 tcf over that five year period.

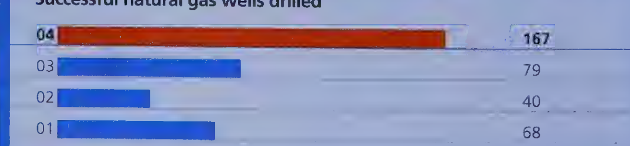




Average annual production (mmcf/d)



Successful natural gas wells drilled



Northwest Alberta

The asset

This region contains exceptional exploration and exploitation opportunities as well as an extensive, owned and operated infrastructure that had been overbuilt by its previous owner. In this region, we produce liquids rich natural gas from multiple, often technically complex horizons, with formation depths ranging from 3,000 to 15,000 feet. We have operated in this region since mid-2002 when much of the landholdings and infrastructure were acquired as part of a larger transaction. Landholdings in the region are now 1.7 million undeveloped acres.

Exploitation

In this region we drilled a total of 138 wells including 58 wells targeting natural gas from horizons deeper than 6,500 feet and 22 wells targeting more conventional natural gas targets. We also continued development of the Cardium sands during 2004 drilling 69 wells with a 100% success rate. The risks and costs associated with this complex tight sand were greatly reduced through a detailed geological and capital cost review undertaken in 2002 and 2003. The benefits of this exercise were greater drilling success and lower capital costs per well.

Acquisitions

An acquisition in the second quarter greatly enhanced our undeveloped Foothills acreage and will provide a new focus for our deeper exploration plans. Other assets acquired in the fourth quarter added complementary lands and production to our existing asset base and the acquisition of assets in the Saddle Hills area has provided an excellent opportunity to expand our core region to the north.

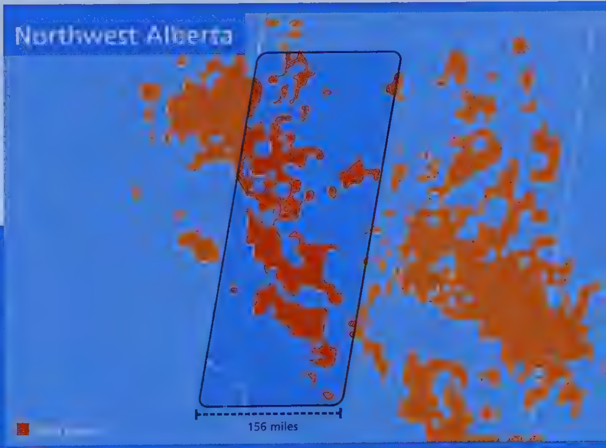
Exploration

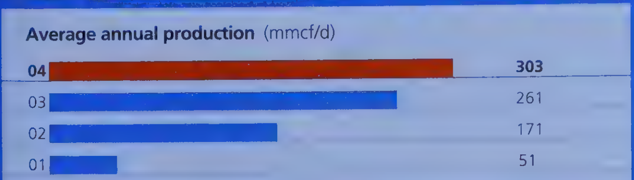
We now have a competitive advantage in the region. Our achievements in 2004 were to develop an extensive knowledge base on the Bluesky, Gething and Cadomin sands. These lands represent significant long term resource potential where initial flow capabilities can exceed 5 mmcf/d per well. It is these deeper horizons that will form the basis of long-term sustainable natural gas development in the region.

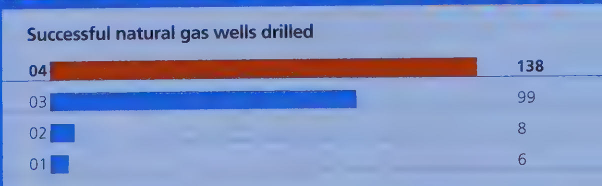
What to expect in 2005 and beyond

The 2005 drilling program includes almost 200 wells, with about 75 wells targeting Cardium and a similar number targeting deeper sands. Today we have identified about 900 locations to be drilled over the next five years. Bluesky, Gething and Cadomin targets represent a little over 50% of this project portfolio.

The strong growth profile for this region is a major driver of our corporate natural gas growth strategy. We expect resource potential of 1.5 tcf over the next five years.







North American Natural Gas (cont.)

Northern Plains

The asset

Natural gas in the Northern Plains core region is produced from shallow, low-risk, multi-zone prospects and represents about 32% of our natural gas production today. This is a mature operating region, however through ongoing exploitation activities and by optimizing operations, it continues to be one of the best cashflow generating regions in the Company. In a mature basin, the key to success is to maintain high utilization of infrastructure and control capital through well planned and efficiently executed drilling and recompletion programs.

Exploitation

Our strategy in this region is to dominate its vast 7 million acre land base and target low-risk exploration and synergistic property acquisitions to maintain our area dominance and ensure high infrastructure utilization. Further, in regions such as this, re-examination of mature properties can often lead to new opportunities, especially given generally higher commodity prices. In 2004, this portfolio re-examination led to expanded programs for both McMurray and Viking natural gas sands. During 2004, 205 wells targeting natural gas were drilled in the region with a success rate of 80%.

A significant challenge in 2004 was the mitigation of the impact of the Alberta regulatory body mandated natural gas production shut-ins due to bitumen conservation measures. Our strategy was very effective - through uphole well recompletion 7 mmcf/d of the total 16 mmcf/d of shut-in production was replaced.

Acquisitions

In 2004, two significant acquisitions added to our production and land base in the Northern Plains core region. In February 2004, the Petrovera Partnership acquisition added 9 mmcf/d of production and added significant undeveloped acreage for future natural gas development.

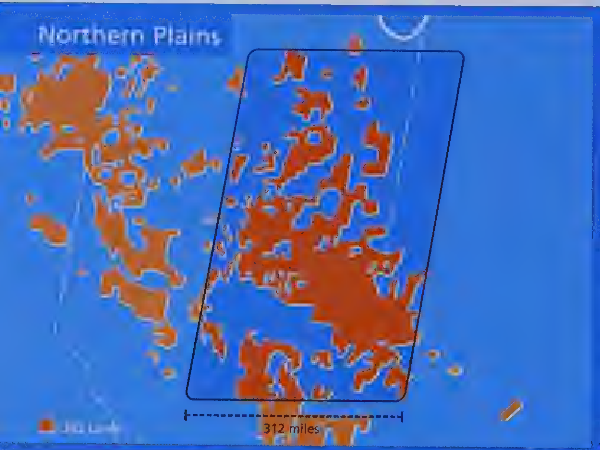
A second acquisition announced in the fourth quarter added 452 thousand acres of undeveloped natural gas lands and 37 mmcf/d of production. These assets fit extremely well with our existing operations and provide excellent opportunities to consolidate facilities, improving utilization and reducing operating costs. The opportunities created by this latter acquisition include an inventory of 30 new well locations and more than 140 recompletion opportunities.

The upside opportunity

Canadian Natural has the second largest landholding position in the Western Canadian Sedimentary Basin resulting in significant Coal Bed Methane ("CBM") potential in the Mannville and Horseshoe Canyon coals. We have taken a measured approach to the development of CBM on our acreage drilling 31 wells in 2004. In 2005 we will continue to develop additional Horseshoe Canyon costs and pursue testing of other CBM prospects on Canadian Natural acreage.

What to expect in 2005 and beyond

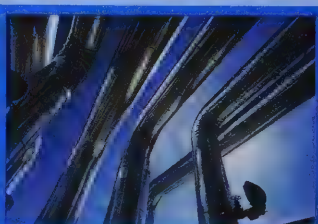
Seventy Horseshoe Canyon CBM wells are planned as the Company continues to expand its expertise and commence commercial CBM operations. Our five year drilling inventory includes over 1,000 shallow locations, 335 conventional locations and over 300 Horseshoe Canyon CBM wells.

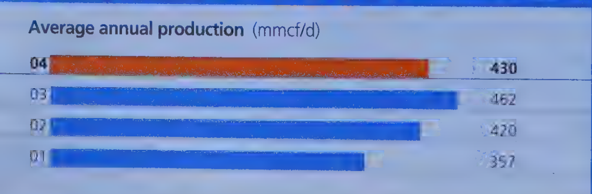


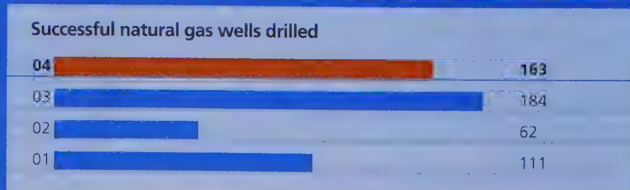
Five year drilling forecast

North American natural gas drilling

	Northeast British Columbia	Northwest Alberta
2005E	240	194
2006E	242	180
2007E	254	185
2008E	267	170
2009E	280	170
Total	1,283	899







Southern Plains

The asset

Natural gas in the Southern Plains core region is produced from shallow, low-risk wells drilled at high densities and from more conventional multi-zone prospects. We've operated in this core region since 1996, growing production by an average of 6% per annum. While production on a per-well basis is the lowest among the core regions, shallow gas well drilling costs are low providing attractive finding costs. In addition, annual production declines in the region are also the lowest at 18%, yielding long-term value.

The key to success in this region is to utilize area dominance to add low cost volumes. This includes having a land base capable of supporting a large inventory of drilling and recompletion prospects.

Exploitation

The 2004 drilling program of 232 wells was reduced from the planned amount during the year as a result of capital reallocation following the successful heavy crude oil and natural gas property acquisitions in other core regions. During the year, Canadian Natural continued development of its shallow gas play in Etzikom, first described in 2003, adding four mmcf/d since inception.

Acquisitions

In the fourth quarter, the acquisition of oil properties in the Taber area added 900 boe/d to our production base. These properties are a strong fit operationally and provided immediate opportunities for operating cost reductions, well optimization, as well as adding further to our waterflood opportunities.

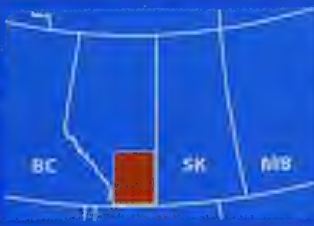
The upside opportunity

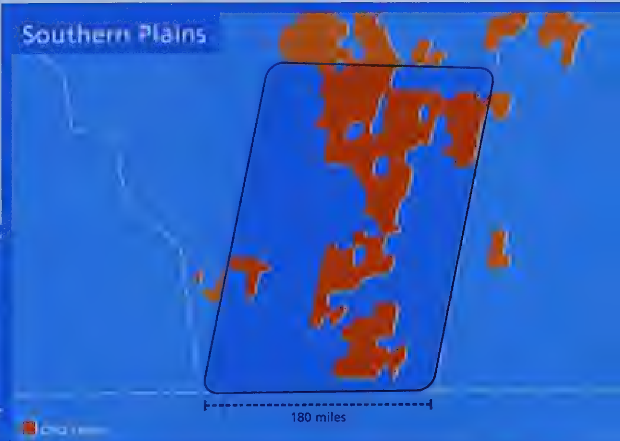
Canadian Natural holds a significant land position in the Southern Plains yielding a large inventory of shallow and conventional drilling and recompletion opportunities. In 2004, we determined that by combining shallow gas drilling programs with field compression and optimization, considerable improvements in production were possible. This is in evidence at Princess, where production improved by 50% in September having drilled only 40 wells. As a result, future drilling plans have been adjusted to reflect this opportunity which will reduce ultimate capital requirements and generate stronger finding and onstream costs relative to the previous plan.

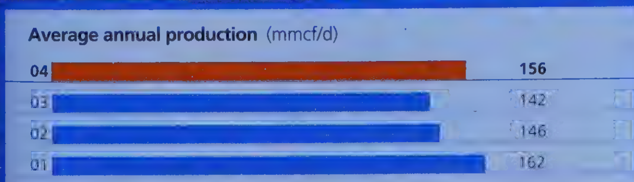
What to expect in 2005 and beyond

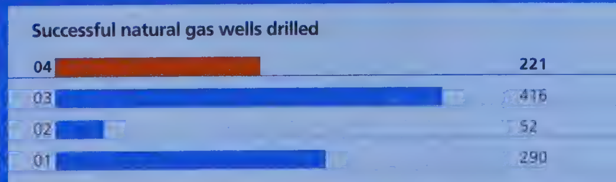
The 2005 drilling program is comprised of approximately 394 wells, with over 250 targeting low-risk, shallow natural gas. Canadian Natural has integrated compression optimization with shallow gas drilling programs into our five-year plan. The current five-year drilling inventory in the Southern Plains holds over 1,000 shallow gas locations and 350 conventional gas locations.

Northern Plains	Southern Plains
205	394
207	326
182	341
162	292
152	323
908	1,676









North American Crude Oil and NGLs

Light crude oil and NGLs

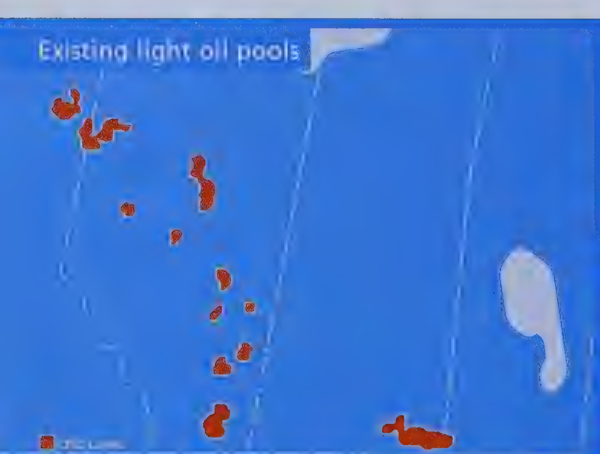
The asset
We produce light crude oil and NGLs in all of our western Canadian core regions. In North America our light crude oil assets are largely developed, however, we continue to grow light crude oil production through a combination of acquisitions, waterflood optimization and development drilling. Many of the Company's pools are produced under waterflood resulting in significantly higher recovery factors and lower production decline rates. NGL production represents 28% of our light crude oil and NGLs production and is concentrated in the liquids rich region of Northwest Alberta.

Exploitation
In 2004, Canadian Natural's light crude oil drilling program had two thrusts: low risk, infill drilling in oil pools located in the Northern Plains and Southeast Saskatchewan core regions and waterflood optimization programs in Northern Plains, Southern Plains and Southeast Saskatchewan. As noted earlier, we continue to pursue development and optimization opportunities on the waterflood projects we operate.

Acquisitions
In the fourth quarter, Canadian Natural acquired properties located in the Dawson area of Northern Plains. We believe there are excellent opportunities for infill drilling in these highly productive Slave Point oil pools as well as incremental recovery potential through waterflooding. We have significant waterflood experience in the WCSB by virtue of operating 79 active projects. The existing productive oil wells at Dawson have also identified very prospective uphole natural gas development opportunities.

The upside opportunity
Canadian Natural has chosen to focus on improvements in waterflood efficiencies to enhance light crude oil reserves because of the Company's large developed asset base and because of limited light crude oil growth opportunities in the WCSB. Our developed assets are massive and a one percent improvement in recovery would yield an incremental 42 million barrels of oil. We focus on waterflood optimization through detailed reservoir characterization, analysis of pattern performance, improved well operating practices and improved fluid processing at the surface. In addition to enhanced oil recovery techniques our defined plan includes almost 400 new well locations to be drilled over the next five years. This will translate into modest production growth beyond normal declines during this period.

What to expect in 2005 and beyond
For 2005, Canadian Natural will continue to focus on waterflood and tertiary recovery opportunities, including an in-depth evaluation of the Dawson property. Approximately 100 new wells are planned and we continually look for new opportunities in our basin and within our own portfolio of assets. In 2005, we will commence testing of a polymer enhanced waterflood in Southern Plains in pursuit of incremental recovery beyond traditional waterfloods. We expect to be able to maintain current levels of light production for several years, with acquisitions providing additional growth potential.



Average annual production (mbbl/d)

04	47
03	47
02	42
01	35

Successful crude oil wells drilled

04	45
03	50
02	16
01	25

Pelican Lake crude oil

The asset

This large, shallow oil pool in our Northern Plains core region has been developed exclusively with horizontal wells. This technology minimizes surface disturbance and environmental impact, reduces development costs and results in significantly greater well productivity in comparison to alternate techniques. We own and operate more than 700 horizontal wells and three centralized treating facilities in the area. Although priced similarly to heavy crude oil, our Pelican Lake crude oil production yields netbacks typical of medium oil due to our ability to maintain low operating costs.

Exploitation

We continue to pursue drilling opportunities for primary production but will reach the limits of our prospective acreage in the near future. While we currently forecast a five percent recovery factor from primary production, the developed reservoir on our leases contains approximately 2.8 billion barrels of oil in place, making it very attractive for secondary or tertiary recovery.

In pursuit of these incremental reserves, we have commenced the phased development of a waterflood project, with approximately 13% of the field being under waterflood at the end of 2004. The waterflood, combined with the drilling of 34 additional new wells has stabilized production at approximately 20 mbbl/d. Current waterflood implementation plans include converting a further 30 Pelican Lake producing wells to water injectors and drilling 67 new wells in 2005 as producers.

Ongoing waterflood conversion is expected to double primary recovery factors on approximately 50% of the field. Future development phases have been planned for implementing waterflood in the remainder of the targeted reservoir.

The upside opportunity

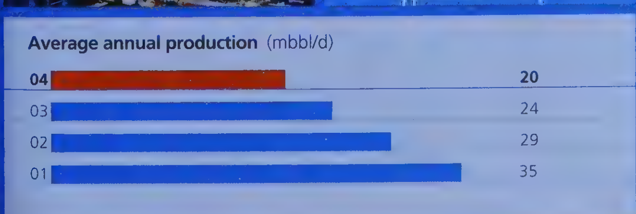
During 2005, we will also evaluate the use of polymer to enhance waterflood recovery by implementing a pilot test with two horizontal injection wells combined with five horizontal production wells. While it is too early to judge the technical and economic success of this tertiary recovery process it is believed that polymer flood could yield incremental recoveries of five percent over that of waterflooding alone*. This could amount to 130 mmbbl of incremental recovery at Pelican Lake.

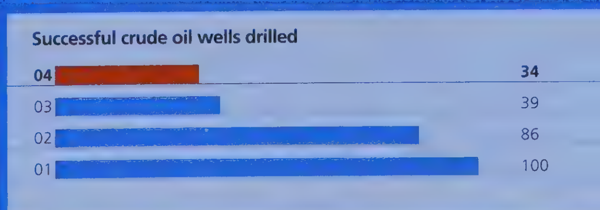
Exploration

As noted earlier, we are nearing the end of primary drilling opportunities in the Pelican Lake pool however we believe the region still holds some potential for oil accumulations recoverable by primary means. In 2005, we plan to drill six stratigraphic wells in search of of other smaller Wabasca pools in the region.

What to expect in 2005 and beyond

We currently expect that our waterflood project combined with the 230 new well locations in our five year plan will keep production stable or modestly growing over the next several years. Success in the polymer flood pilot could mean growth beyond this level. The pursuit of Enhanced Oil Recovery techniques will continue and have already extended the field life of Pelican Lake adding significant value for our shareholders.





North American Crude Oil and NGLs (cont.)

Primary heavy crude oil

The asset

We are Canada's largest heavy crude oil producer, having expertise in both primary and thermal recovery techniques. Growth in primary heavy crude oil production has been achieved through drilling as well as strategic, synergistic acquisitions. Heavy crude oil is produced using primary production mechanisms from shallow, low-risk, multi-zone horizons. This leads to low finding and development costs, exceptional drilling success rates and many subsequent recompletion opportunities. The region is also natural gas prone and heavy crude oil development drilling frequently leads to synergistic natural gas pool discoveries.

Exploitation

With over 1.5 million acres of undeveloped land and 0.3 million acres of developed land, we dominate production and operations within the Bonnyville/Lloydminster primary producing area of our Northern Plains core region. This dominance allows us to minimize capital by conducting large scale drilling and development programs and to control our operating costs by owning and operating central treating facilities and maximizing their utilization.

Acquisitions

In early 2004, Canadian Natural acquired additional properties which included 28 mbbl/d of heavy crude oil production, five oil processing facilities and 0.7 million acres of undeveloped land. By levering our vast infrastructure, including sand handling and trucking operations, we were able to reduce field operating costs on these properties by $0.60/bbl. This opportunistic acquisition also strengthened our already robust project inventory by adding over 300 new drilling locations and 400 recompletion opportunities.

The upside opportunity

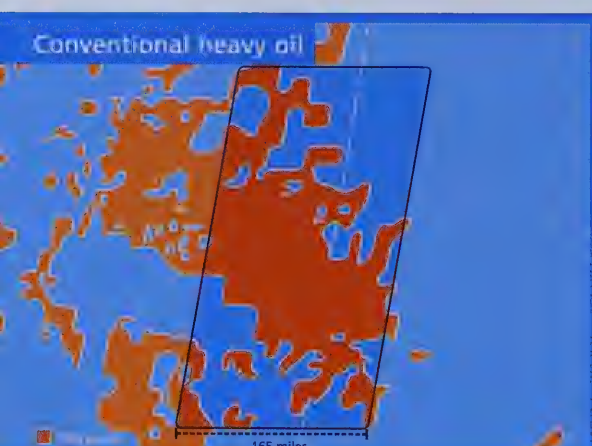
We continue to pursue the development of applicable technologies to further improve oil recovery beyond primary. Our developed lands are estimated to have 7 billion to 10 billion barrels of original oil in place with an ultimate recovery factor ranging from 12% to 17%. A 1% increase in recovery would equate to over 70 million barrels of recoverable oil easily justifying our pursuit of new recovery technologies.

Technology highlight

The ECHO Pipeline is a wholly owned and operated pipeline which transports raw undiluted heavy crude oil into our blending facilities at Hardisty, Alberta. The pipeline moves this undiluted heavy crude oil by retaining the heat used in normal crude oil treating operations via an insulated shell and coating surrounding the pipe. Use of the retained heat saves us additional energy and operating costs. The heated oil's shipping viscosity equates to that of a normal pipeline running at cooler temperatures and using diluents for viscosity reduction. The undiluted crude oil is blended into the Western Canadian Select crude oil stream with a variety of diluents allowing us to take full advantage of the lowest cost diluent during any market cycle.

What to expect in 2005 and beyond

For 2005, 400 locations are forecast to be drilled and 360 wells will be recompleted. Over the medium and longer term we remain disciplined in our development of additional heavy crude oil. Our base forecast assumes that over 1,350 new wells will be drilled during the next five years, keeping production relatively flat. As new markets are created for heavy crude oil we have the capability of ramping up this drilling effort and increasing production, however, we will not proceed until we are assured of this new demand.

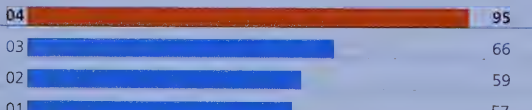


Five year drilling forecast

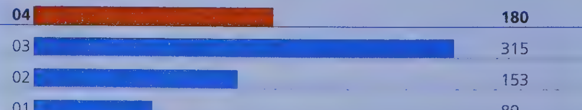
North American crude oil and NGLs drilling

	Light crude oil	Pelican Lake crude oil
2005E	101	67
2006E	86	74
2007E	73	39
2008E	66	24
2009E	59	28
Total	385	232

Average annual production (mbbl/d)



Successful crude oil wells drilled



Thermal heavy crude oil

The asset

We are the second largest producer of crude oil recovered by thermal processes in Canada. We employ two distinct recovery processes: Cyclic Steam Stimulation ("CSS"), and Steam Assisted Gravity Drainage ("SAGD") and currently operate three thermal projects: the large commercial CSS project at Primrose, the Tangleflags SAGD project and the Primrose East SAGD pilot project. We have extensive expertise and operating experience in thermal recovery and the recovery processes employed have been fully proven with more than 15 years of operating history.

Exploitation

Our near term focus is the expansion of the Primrose thermal project at Cold Lake where current infrastructure consists of a steam cogeneration plant, oil and water processing facilities and over 350 active horizontal wells. In 2004, we continued with the long-term drilling program that commenced in early 2003, with a total of 51 additional horizontal wells being drilled. Production from these wells will fill both our existing and expanded facilities. Optimization of the Primrose facilities combined with low-risk development drilling will create one of the most economic in-situ developments in Canada.

The upside opportunity

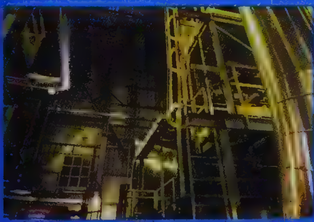
Expected recovery factors from our CSS projects are approximately 25%. We believe that given post CSS production reservoir temperatures of 150 degrees Celsius, a systematic study of drive mechanisms to take advantage of that trapped heat and energy is warranted. A long-term enhanced recovery prize of 400 million bbl of resources is possible and as such we have embarked upon a three stage evaluation program that will examine the injection of : i) cyclic gas; ii) cyclic gas combined with solvent; and iii) solvent combined with steam (sometimes referred to as "vapex").

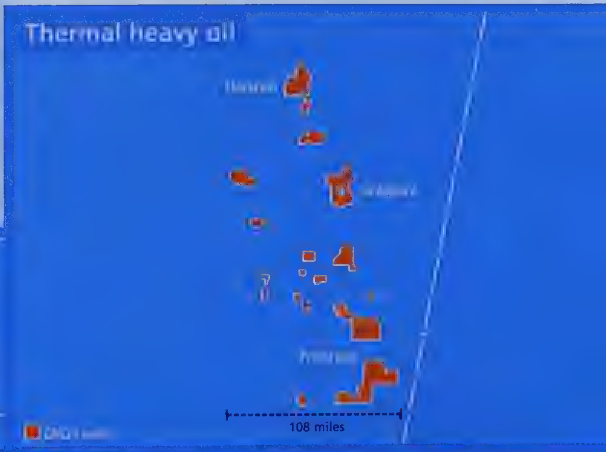
What to expect in 2005 and beyond

For 2005, approximately 105 thermal horizontal wells are expected to be drilled in addition to ongoing delineation of our in-situ lands. Primrose development will continue with the expansion and de-bottlenecking of associated facilities. Start-up of the expanded facility at Primrose North is forecast for late 2005 with incremental production of 30 mbbl/d forecast for 2006. We are also continuing to focus on improving oil recovery through field testing and research initiatives.

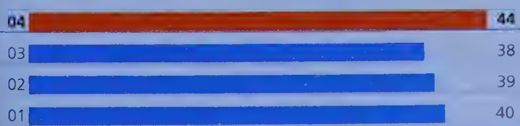
Mid-term growth will come from the commercial development expected in 2009 of our Primrose East project, adjacent to the existing Primrose operations. In the long term we will focus on the development of our massive oil sands leases in the Athabasca area. We hold large leases in the Horizon and Gregoire Lake areas. At Horizon where the oil sands are too deep to mine, a potential 70 mbbl/d SAGD project is envisioned while at Gregoire Lake, there are four industry projects planned or operating adjacent to the our leases. We continue to evaluate each of these leases in order to maximize volume creation through effective development in an orderly fashion. We have a significant and high quality resource base that will deliver continued production growth over the long term.

Primary heavy crude oil	Thermal heavy crude oil
398	105
292	125
235	85
213	165
213	64
1,351	544





Average annual production (mbbl/d)



Successful crude oil wells drilled

International Crude Oil

United Kingdom portion of the North Sea

The asset
We operate approximately 99% of our production with an average ownership interest of 80%. Operations are currently run from four hubs: the Ninian and Murchison hubs in the Northern North Sea and the Banff/Kyle and T & B Block hubs in the Central North Sea. By maintaining control of these assets we have been able to minimize operating costs and control the capital allocation and pace of our exploitation plans for the properties.

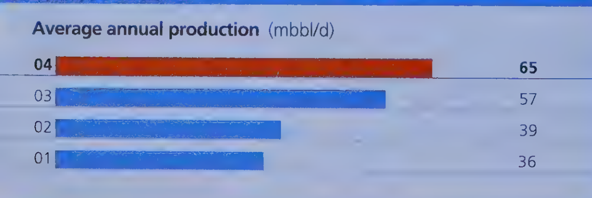
Exploitation
Our achievements in the North Sea are a result of the successful utilization of our mature basin expertise. We infill drill, recomplete, workover wells and optimize waterfloods to increase production, lower costs and extend field life. We also utilize our large infrastructure to conduct near pool exploration. Even smaller pools can be brought on at low cost further utilizing existing infrastructure life and adding significant value. At Banff, we have commenced re-injection of associated natural gas back into the reservoir. This maintains the pressure within the pool and will thereby result in higher overall recovery of crude oil from the pool.

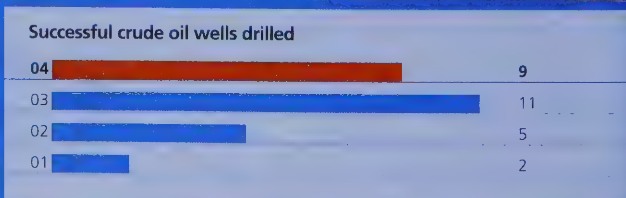
Acquisitions
During 2004 we acquired operated interests in T-Block (Tiffany, Toni and Thelma fields) and B-Block (Balmoral, Stirling and Glamis fields), together with associated production facilities and adjacent exploration acreage. Ownership levels of 100% on the T-Block and between 69% and 75% of the B-Block were achieved, adding about 16,000 boe/d during the second half of 2004. This provided an additional base to expand our successful exploitation activities in the North Sea. Eight drilling and nine workover opportunities were identified prior to acquisition, with four wells planned for 2005.

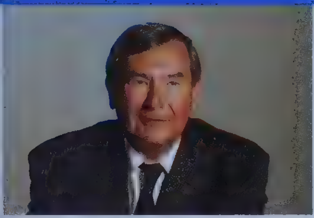
The upside opportunity
We believe that the current environment within the North Sea is similar to that of the WCSB in the early 1990s. The basin is mature and many of the major operators are reducing activity levels or looking at divesting of properties. Exploitation oriented companies like Canadian Natural are proactively pursuing such opportunities. Should such exploitation opportunities fit, we could continue to grow our North Sea production levels. Absent these opportunities, production levels should remain relatively flat.

What to expect in 2005 and beyond
For 2005, 15 well locations are expected to be drilled, including the Nadia Field. This Ninian satellite pool has the potential to yield results similar to the Columba Terraces. The Tiffany platform drilling rig is undergoing major refurbishment in order to undertake a three well program. Two wells will be drilled at the Thelma field targeting unswept areas of the pool.

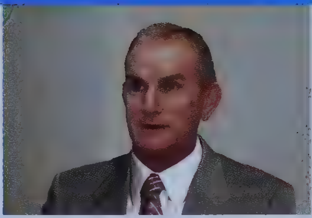
As noted above, we continue to look for accretive acquisitions with exploitation upside for growth. With our current portfolio we expect to maintain or modestly grow current production levels over the next three to four years.







Allen M. Knight
Senior Vice-President,
International &
Corporate Development



Martin Cole
Vice-President & Managing
Director, CNR International

Offshore West Africa

The asset

Canadian Natural has three exploration Blocks comprising approximately 460 thousand gross acres of land located offshore Côte d'Ivoire. We are currently continuing the development of three well defined pools. East Espoir averaged approximately 12 mboe/d of crude oil and associated natural gas in 2004. Four additional infill wells accessing new regions of the reservoir are expected to augment this production late in the first quarter of 2005. The Baobab medium crude oil development continues on-time and on-budget with first oil expected in mid-2005 at 24 mbbl/d. Finally, the development of the West Espoir pool is expected to commence first production in mid-2006 with production eventually reaching approximately 11 mboe/d.

Exploitation

Exploitation techniques on these fields include waterflood management, infill drilling, horizontal wells to manage recovery and targeted near-pool exploration where even smaller pools become economic through the utilization of adjacent facilities. During 2004 our engineering and geological analysis indicated that the reservoir at East Espoir was larger than originally thought. As a result, in 2005 we will tap these undeveloped portions of the pool with four new infill wells. An example of near-pool development is the Acajou field which will be eventually tied back to the East Espoir facilities as space become available in these facilities.

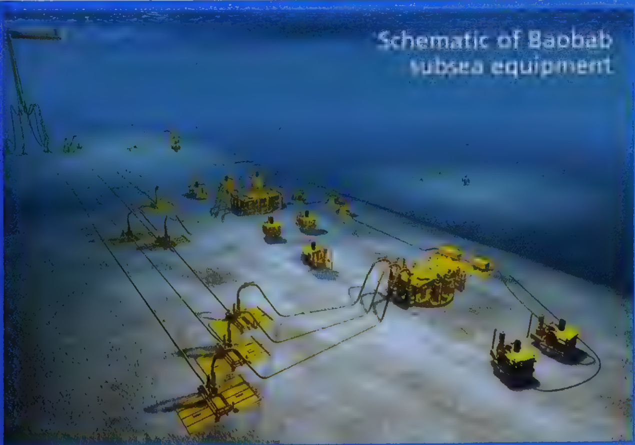
As noted earlier the 61 mmbbl Baobab development continues on-time and on-budget. This deepwater field was discovered just four years ago and is now close to first oil, a significant accomplishment in itself. Utilizing a system of subsea equipment and an FPSO crude oil will be produced from this reservoir located in more than 3,300 feet of water. We have developed an extensive knowledge of offshore operations and this will be the sixth FPSO/FPV that we have operated. Production from this field will ramp from initial rates of about 24 mbbl/d to 35 mbbl/d in 2006 where they are expected to stabilize for a few years.

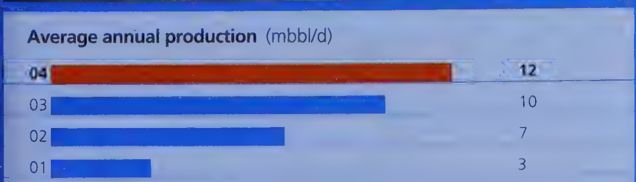
The upside opportunity

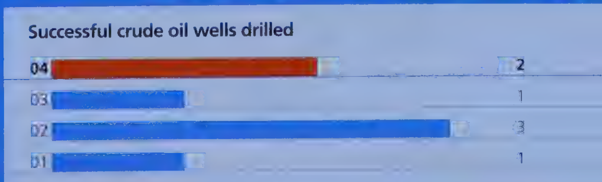
Exploration continues on the extensive lease holdings we have in Côte d'Ivoire. In early 2005 we drilled two targets identified in 2003/4, Acajou and Zaizou, however neither were successful. We believe that while disappointing, additional exploration upside will accrue in Côte d'Ivoire over time. To date hydrocarbons and high quality reservoir characteristics have been found in five of six separate structures drilled. Ongoing geological studies seek to better understand oil flow in the basin with a view to continued exploration in 2006 and beyond. A further high risk, high reward play continues to be matured in offshore South Africa. While the size of the pools are very significant, so too are the technical challenges associated in this offshore environment. We will continue to allocate a small amount of exploration capital each year to mature such plays.

What to expect in 2005 and beyond

For 2005, four wells on East Espoir will be drilled to access untapped areas of the reservoir increasing exit volumes by as much as 2 mbbl/d. First production of 24 mbbl/d from the Baobab field is expected mid-2005 and will ramp to 35 mbbl/d in 2006. Development of the East Espoir satellite pool, West Espoir will continue with installation of the well head tower expected late in the year and first production of 11 mboe/d in mid-2006. Essentially, we will have grown our production in Côte d'Ivoire from no production at the start of 2002 to 60,000 boe/d by the end of 2006 – all at highly attractive economics. The growth profile is firmly defined for the next three years – our disciplined approach is delivering the results.

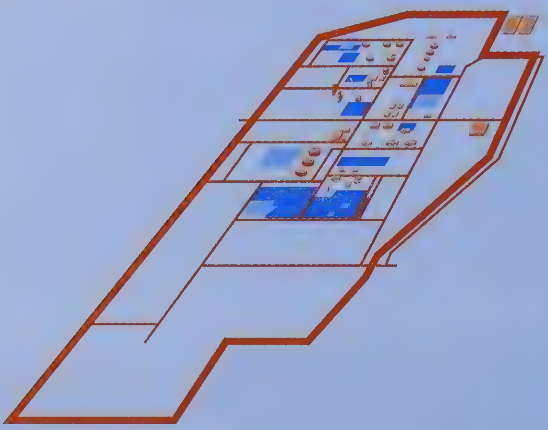






Horizon Oil Sands Project

Schematic of the Horizon Project plant site



The asset

Canadian Natural owns a 100% working interest in 116,595 acres in the Athabasca Oil Sands area of northern Alberta, about 70 km north of Fort McMurray. The Horizon Project includes a surface oil sands mining and bitumen extraction plant coupled with on-site bitumen upgrading to produce a 34-36° API SCO, and associated infrastructure.

The Horizon Project is designed as a three phased development. Phase 1 production is expected to begin in 2008 ramping up to 110 thousand barrels per day of SCO. Phase 2 will increase production to 155 thousand barrels per day of SCO in 2010. Phase 3 will further increase production to 232 thousand barrels per day of SCO in 2012 and operate for 37 years. Production is limited only by size of facilities – no production declines normally associated with oil and gas operations occur. The result is tremendous cash flow with little capital reinvestment required. Sustaining capital is only about $1.10/bbl once the plant is up and running – resulting in significant free cash flow.

2004 in review

In the development of the Horizon Project plan, our analysis was exhaustive and we put in place the foundation for a successful project. This included an extensive "lessons learned" activity from predecessor projects that was used in developing our execution plan, selecting technologies and reducing our risk profile. Essentially we determined that in order to maximize value to shareholders and to avoid capital expenditure overruns, upfront definition of "what we want to build" and "how we want to build it" would be necessary.

Our phased approach is the most suitable for developing a project of this size in a resource constrained environment; it mitigates the effects of growth on local infrastructure and provides us with improved cost and project control. Canadian Natural invested four years and over $500 million in front end analysis, design and engineering yielding an exceptionally high level of technical definition and certainty. The emphasis on project definition facilitated the procurement of fixed price and lump sum bids on large portions of the project – reducing many of the project risks associated with the construction marketplace. A logistics plan has been developed taking advantage of our plant site size with many lay down and staging areas to allow inventorying of required materials in a logical sequence to support efficient installation and well in advance of any item becoming critical.

Réal J.H. Doucet
Senior Vice-President,
Oil Sands

During 2004, over 170 tender packages and requests for proposals were issued to a variety of suppliers around the globe. The resulting quotes were received and evaluated by us early in the fourth quarter and were the basis for our Board of Directors' sanction of the Horizon Project in February 2005. In completing their bid submissions, suppliers considered the impact of significantly higher world steel prices and the high level of competitive activity in Alberta. This resulted in estimates for Phase 1 of the Horizon Project being revised from $5 billion to $6.8 billion. Similarly, total project costs were estimated to increase to $10.8 billion from the original estimate of $8.5 billion.

As a result of these activities, the Horizon Project has a construction risk profile unlike anything completed in the oil sands before. The majority of Phase 1, about 68%, will be completed under fixed price agreements. With these agreements the biggest risk is scope change however, having a completed the front end engineering and providing a high degree of definition the project has reduced the chance of a major scope change. An additional 22% of the project is estimated to be based on reimbursable contracts, and similarly a high degree of certainty on engineering and construction requirements completed – again reducing risk. Finally, a 10% contingency allowance has been built into cost estimates.

Canadian Natural has segregated the project into 21 manageable pieces and limited the amount of work to any single contractor. This reduced the project exposure to any single contractor both financially and operationally.

In the field we commenced site preparation work during 2004. Included in this is site clearing, drainage and installation of deep underground facilities such as electrical, natural gas, water and sewage. Similarly, work on access roads and construction of worker camps is well underway. At the end of 2004 the services of 1,280 people were active on the Horizon Project; including 330 people on site, 350 employees in our Calgary project office and an additional 600 people employed by engineering firms.

The Horizon Project advantage

The technology at the Horizon Project is based on that currently in use at existing plants, effectively mitigating technology risk in Phase 1. That being said, the plant has been configured in a manner to maximize benefits from all the technologies. For example, Horizon Project will have a very high level of heat sharing and integration between the facilities, reducing both natural gas consumption and greenhouse gas emission levels.

The geological risk associated with the project is very low. On this lease, over 16 stratigraphic wells per section have been drilled to identify overburden levels, and test the ore composition and quality. The result is a well designed mine plan that has been optimized to support the bitumen extraction and processing.

To ensure efficient construction Horizon Project has developed an "80% rule" – with about 80% of the engineering effort completed prior to major facility construction – this will allow us to ensure materials are available prior to construction and minimize rework. In addition we believe that our execution and labour strategy combined with the fly-in fly-out ability of workers will position the Horizon Project as "the employer of choice" in the region.

At 34 degree API gravity, low sulphur and fully sweet, the project is designed to produce the highest quality SCO currently produced from the region, somewhat reducing marketing risks.

Finally, this asset has been designed to accommodate future growth. The large footprint allows for easy access to all parts of the plant and ensures that future production expansions would have minimal impact on existing operations.

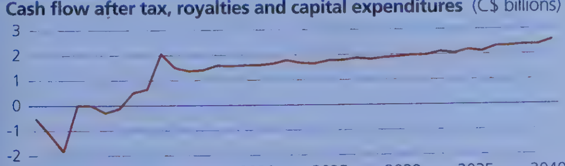
Why are oil sands mining projects so robust?

Oil sands mining projects are considered to be world class legacy assets due to their:

- lower geological risk profile
- high quality, low sulphur synthetic crude oil output
- reliable, proven technologies
- absence of production declines normally associated with oil and gas operations
- high free cash flow generation capability due to minimal capital reinvestment requirements

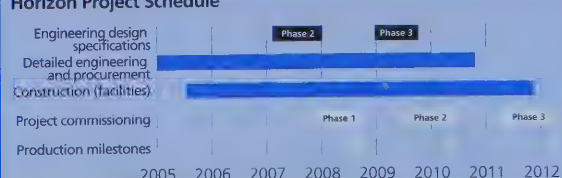
Preconstruction returns on capital are robust, with the Horizon Oil Sands Project generating 15% returns. In addition, the net asset value from this project will continue to build throughout the construction period due to the value of the significant free cash flow to be generated.

Cash flow after tax, royalties and capital expenditures (C$ billions)



Note Based upon US$28/bbl WTI with 2.5% price and cost escalation.

Horizon Project Schedule



Douglas A. Proll
Senior Vice-President,
Finance

The economics

The Horizon Project generates a strong return on employed capital of 15% after tax assuming a US$28/bbl WTI price. Of significance and sometimes missed in net present value analysis is the warrant value of the significant free cash flow generated on the back end of the project. This is a mining project; there are no production declines and maintenance capital is nominal, hence, this project will provide very significant free cash flow for decades.

What to expect in 2005 and beyond

Following the approval of the project by our Board of Directors on February 9, 2005, a number of bid packages were immediately awarded to suppliers. Simultaneous with this approval qualified independent reserves evaluators booked 1.9 billion barrels of proved bitumen reserves and 3.3 billion barrels of proved and probable bitumen reserves for the first three phases of the project.

Site clearing, drainage and deep underground facility installation is expected to be completed in time for turn over of the construction site to our contractors with the first area turned over in April. Construction activities expected during the last half of the year include fabrication of buildings, installation of camps, and completion of the site aerodrome. The plan is very well defined through to first oil in 2008 and now we will execute.

We have a strong and robust financing plan in order to ensure that we have the ability to complete the project and retain a 100% working interest. This plan has been predicated upon a US$28/bbl WTI pricing, with further stress allowance considered. Under this scenario we remain well within our targeted financial stewardship ratios by utilizing conventional operation's free cash flow and debt sources of financing. Further comfort has been obtained by the procurement of commodity hedge pricing significantly above this US$28/bbl level for portions of 2005/6 production.

The upside opportunity

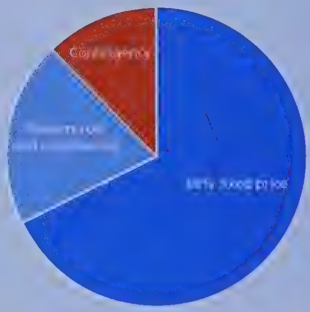
We believe that our land assets, site layout, size, and the manner in which we have been planning this Project will facilitate increases in production beyond the 232,000 bbl/d SCO that is currently articulated. Our internal estimates of resource potential, based upon our stratigraphic well drilling program accumulate to approximately six billion barrels of mineable bitumen throughout our Horizon Project leases, a potential increase of 70%.

How will we control project costs and execution?

Our plans have not wavered over the past four years. As new participants in the industry we wanted to mitigate risks to the greatest extent possible. That meant having a higher degree of engineering definition than previously sought by industry. We further believed that if this high level of engineering would be attained then we would be able to further mitigate costs by obtaining fixed bids.

Following an investment of four years and $500 million we achieved an exceptionally high level of front end design. This has translated into a high degree of cost certainty for Phase 1 construction costs. We know what we want to build and how we want to build it. Our suppliers have been able to work with us to further define and Phase 1 costs through use of fixed price bids on 68% of expenditures.

Total Phase 1 costs (~C$6.8 billion)



Management's Discussion and Analysis

Special note regarding forward-looking statements

Certain statements in this document or documents incorporated herein by reference for Canadian Natural Resources Limited (the "Company") may constitute "forward-looking statements" within the meaning of the United States Private Litigation Reform Act of 1995. These forward-looking statements can generally be identified as such because of the context of the statements including words such as the Company "believes", "anticipates", "expects", "plans", "estimates", or words of a similar nature.

The forward-looking statements are based on current expectations and are subject to known and unknown risks, uncertainties and other factors that may cause the actual results, performance or achievements of the Company, or industry results, to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such factors include, among others: the general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; the foreign currency exchange rates; the economic conditions in the countries and regions in which the Company conducts business; the political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; the industry capacity; the ability of the Company to implement its business strategy, including exploration and development activities; the impact of competition, availability and cost of seismic, drilling and other equipment; the ability of the Company to complete its capital programs; the ability of the Company to transport its products to market; the potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas; the availability and cost of financing; the success of exploration and development activities; the timing and success of integrating the business and operations of acquired companies; the production levels; the uncertainty of reserve estimates; the actions by governmental authorities; the government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations); the asset retirement obligations; and other circumstances affecting revenues and expenses. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors, and management's course of action would depend upon its assessment of the future considering all information then available.

Statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. The Company assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Special note regarding non-GAAP financial measures

Management's discussion and analysis includes references to financial measures commonly used in the oil and gas industry, such as cash flow, cash flow per share and EBITDA (net earnings before interest, taxes, depreciation, depletion and amortization, asset retirement obligation accretion, unrealized foreign exchange, stock-based compensation expense and unrealized risk management activities). These financial measures are not defined by generally accepted accounting principles ("GAAP") and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate the performance of the Company and its business segments. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with Canadian GAAP, as an indication of the Company's performance.

Management's discussion and analysis

Management's discussion and analysis ("MD&A") of the financial condition and results of operations of the Company should be read in conjunction with the Company's audited consolidated financial statements and related notes for the year ended December 31, 2004. The consolidated financial statements have been prepared in accordance with Canadian GAAP. A reconciliation of Canadian GAAP to United States GAAP is included in note 17 to the consolidated financial statements. All dollar amounts are referenced in Canadian dollars, except where noted otherwise. The calculation of barrels of oil equivalent ("boe") is based on a conversion ratio of six thousand cubic feet ("mcf") of natural gas to one barrel ("bbl") of oil to estimate relative energy content. This conversion may be misleading, particularly when used in isolation, since the 6 mcf:1 bbl ratio is based on an energy equivalency at the burner tip and does not represent the value equivalency at the well head. Production volumes are the Company's interest before royalties, and realized prices exclude the effect of risk management activities, except where noted otherwise. The following discussion and analysis refers primarily to the Company's 2004 financial results compared to 2003, unless otherwise indicated. In addition, this discussion details the Company's capital program and outlook for 2005. The fourth quarter discussion and analysis was included in the Company's fourth quarter press release. This MD&A is dated February 18, 2005.

Objective and strategy

The Company's objective is to increase cash flow, crude oil and natural gas production, reserves and net asset value on a per common share basis through the development of its existing crude oil and natural gas properties and through the discovery and acquisition of new reserves. The Company accomplishes this by having a defined growth and value enhancement plan for each of its products and segments. The Company takes a measured approach to growth and investments and focuses on creating long-term shareholder wealth. The Company effectively allocates its capital by maintaining:

- Balance between its products, namely natural gas, light crude oil, Pelican Lake crude oil (1), primary heavy crude oil and thermal heavy crude oil;
- Balance between near-, mid- and long-term projects;
- Balance between acquisitions, exploitation and exploration; and
- Balance between sources of debt and a strong balance sheet.

(1) Pelican Lake crude oil is 14-17° API oil, but receives medium quality crude netbacks due to low operating costs and low royalty rates.

The Company has expanded its hedging program in an effort to reduce the risk of volatility in commodity price markets and to underpin the Company's cashflow through the Horizon Oil Sands Project ("Horizon Project") construction period.

The Company's crude oil marketing strategy includes displacing medium sour crude oil from PADD II, supporting and participating in pipeline additions, encouraging the development of projects that add conversion capacity, and blending strategy.

Cost control is central to the Company's strategy. By controlling costs consistently throughout all industry cycles, the Company is able to achieve continued growth. Cost control is attained by area knowledge, by core area domination and by operating at a high working interest.

Strategic accretive acquisitions are a key component of the Company's strategy. The Company has used excess cash flows derived from higher than expected commodity prices to selectively acquire properties generating future cash flows in its core regions. These targeted acquisitions provide relatively quick repayment of initial investments and will provide additional free cash flow during the construction years of the Horizon Project while still achieving targeted returns. The acquisitions of the Petrovera Partnership ("Petrovera") and natural gas properties in North America and the acquisition of properties in the central North Sea meet these reinvestment criteria and further enhance the Company's abilities to complete the Horizon Project. This expansion of the conventional asset base also helps reduce the sole project risk exposure associated with this major oil sands development project.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Project. The Company has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of low-risk crude oil and natural gas growth opportunities.

The year ended December 31, 2004, was another successful year in the execution of the Company's strategy. Highlights are as follows:

- Achieved record levels of net earnings;
- Achieved record levels of cash flow;
- Achieved record levels of natural gas and crude oil and NGLs production;
- Achieved the Company's annual production guidance for both natural gas and crude oil and NGLs;
- Completed four strategic acquisitions including:
  - the acquisition of Petrovera;
  - the acquisition of natural gas assets located in the Company's core region of Northeast British Columbia and an extension of its core region in the Foothills area of Northwest Alberta;
  - the acquisition of light crude oil producing properties in the Central North Sea;
  - the acquisition of certain natural gas properties located in Alberta, British Columbia and Saskatchewan;
- Commenced production from a new phase of the Primrose in-situ thermal crude oil development;
- Filed a public disclosure document for regulatory approval of the Primrose East project;
- Received regulatory approvals for the Horizon Project from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Canadian Federal Cabinet;
- Completed the subdivision of its Common Shares on the basis of two for one;
- Increased the quarterly dividend by 33% to $0.10 per common share; and
- Purchased 873,400 common shares for a total cost of $33 million under the Company's Normal Course Issuer Bid.

Net earning and cash flow from operations

Financial highlights ($ millions, except per common share amounts)	2004	2003(1)	2002(1)
Revenue, before royalties	$ 7,547	$ 6,155	$ 4,459
Net earnings	$ 1,405	$ 1,403	$ 539
Per common share – basic (2)	$ 5.24	$ 5.23	$ 2.11
– diluted (2)	$ 5.20	$ 5.06	$ 2.04
Cash flow from operations (4)	$ 3,769	$ 3,160	$ 2,254
Per common share – basic (2)	$ 14.06	$ 11.77	$ 8.82
– diluted (2)	$ 13.98	$ 11.53	$ 8.50
Capital expenditures, net of dispositions (3)	$ 4,633	$ 2,506	$ 4,069

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) Restated to reflect two-for-one share split in May 2004.

(3) In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as Petrovera, for $471 million. Strategically, the acquisition fit with the Company's objective of dominating its core regions and related infrastructure. The Company achieved cost reductions through synergies with its existing facilities, including additional throughput in its 100% owned ECHO Pipeline. The acquisition is included in the results of operations commencing February 2004.

In 2002, the Company paid cash of $850 million and issued 20,016,436 common shares to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement. This was a strategic acquisition as it increased the Company's natural gas production and added a new natural gas core region in Northwest Alberta. The Rio Alto acquisition is included in the results of operations commencing July 2002.

(4) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on net earnings and cash flow from operations. The Company considers cash flow from operations a key measure as it demonstrates the Company's ability and the ability of its business segments to generate the cash flow necessary to fund future growth through capital investment and to repay debt.

($ millions)	2004	2003	2002
Net earnings	$ 1,405	$ 1,403	$ 539
Non-cash items:			
Depletion, depreciation and amortization	1,769	1,509	1,298
Asset retirement obligation accretion	51	62	68
Stock-based compensation	249	200	–
Unrealized risk management activities	(40)	–	–
Unrealized foreign exchange gain	(94)	(343)	(36)
Deferred petroleum revenue tax (recovery)	(45)	(9)	10
Future income tax	474	338	375
Cash flow from operations	$ 3,769	$ 3,160	$ 2,254

The Company achieved record levels of net earnings, cash flow from operations and production in 2004 as a result of strong operational performance combined with strong commodity prices. The strong operating results are attributable to the Company following its defined growth strategy and to the strong asset base the Company has developed over time through organic growth and accretive acquisitions.

Net earnings increased in 2004 to $1,405 million ($5.24 per common share), up from $1,403 million ($5.23 per common share) in 2003 (2002 – $539 million or $2.11 per common share). The increase in net earnings in 2004 is primarily due to higher commodity prices and higher production volumes. These increases were offset by increased depletion, depreciation and amortization expense, increased stock-based compensation expense and decreased foreign exchange gains in 2004. In addition, net earnings were also impacted by the Company's risk management activities as a result of an expanded hedging program (see risk management activities and liquidity and capital resources) and one-time non recurring tax rate reductions.

Cash flow from operations reached record levels in 2004. Cash flow from operations increased 19% to $3,769 million ($14.06 per common share), up from $3,160 million ($11.77 per common share) in 2003 (2002 – $2,254 million or $8.82 per common share). The increase in cash flow from operations resulted primarily from higher product prices and increased production volumes. In 2004, the Company's average price per barrel of crude oil and NGLs increased 16% to $37.99 from $32.66 in 2003 (2002 – $31.22). The Company's average natural gas price increased 5% to $6.50 per mcf from $6.21 per mcf in 2003 (2002 – $3.77 per mcf).

Production volumes before royalties increased 12% to a record 513,835 boe/d, up from 458,814 boe/d in 2003 (2002 – 420,722 boe/d). The increase in production volumes was a result of organic growth and accretive acquisitions. Production of crude oil and NGLs before royalties increased 17% to 282,489 bbl/d, up from 242,392 bbl/d in 2003 (2002 – 215,335 bbl/d). Natural gas production before royalties increased 7% to 1,388 mmcf/d, up from 1,299 mmcf/d in 2003 (2002 – 1,232 mmcf/d).

Operating highlights	2004	2003	2002
Crude oil and NGLs ($/bbl, except daily production)			
Daily production, before royalties (bbl/d)	**282,489**	242,392	215,335
Sales price (1)	**$ 37.99**	$ 32.66	$ 31.22
Royalties	**3.16**	2.77	3.16
Production expense	**10.05**	10.28	8.45
Netback	**$ 24.78**	$ 19.61	$ 19.61
Natural gas ($/mcf, except daily production)			
Daily production, before royalties (mmcf/d)	**1,388**	1,299	1,232
Sales price (1)	**$ 6.50**	$ 6.21	$ 3.77
Royalties	**1.35**	1.32	0.78
Production expense	**0.67**	0.60	0.57
Netback	**$ 4.48**	$ 4.29	$ 2.42
Barrel of oil equivalent ($/boe, except daily production)			
Daily production, before royalties (boe/d)	**513,835**	458,814	420,722
Sales price (1)	**$ 38.45**	$ 34.84	$ 27.02
Royalties	**5.37**	5.20	3.91
Production expense	**7.35**	7.15	5.99
Netback	**$ 25.73**	$ 22.49	$ 17.12

(1) Including transportation costs and excluding risk management activities.

Business environment

	2004	2003	2002
WTI benchmark price (US$/bbl)	**$ 41.43**	$ 31.02	$ 26.11
Dated Brent benchmark price (US$/bbl)	**$ 38.28**	$ 28.83	$ 25.01
Differential to LLB blend (US$/bbl)	**$ 13.44**	$ 8.55	$ 6.50
Condensate benchmark price (US$/bbl)	**$ 41.62**	$ 31.42	$ 26.00
NYMEX benchmark price (US$/mmbtu)	**$ 6.09**	$ 5.44	$ 3.25
AECO benchmark price (C$/GJ)	**$ 6.43**	$ 6.35	$ 3.86
US/Canadian dollar average exchange rate (US$)	**0.7683**	0.7135	0.6368

World crude oil prices remained strong in 2004 due to the strong growth in world-wide demand, particularly in the United States and Asia. World crude oil prices have also been impacted by geopolitical uncertainty in several areas of the world, resulting in concerns around the supply of crude oil. World crude oil prices have been further impacted by weather related issues causing production disruptions in the United States Gulf Coast. West Texas Intermediate ("WTI") averaged US$41.43 per bbl for the year ended December 31, 2004, up 34% compared to US$31.02 per bbl in 2003 (2002 – US$26.11 per bbl). The impact of the higher WTI prices on the Company's heavier crude oil production was mitigated by wider heavy crude oil differentials, which increased 57% to US$13.44 per bbl in 2004, up from US$8.55 per bbl in 2003 (2002 – US$6.50 per bbl). Realized crude oil prices were also impacted by the strengthening Canadian dollar.

North American natural gas prices remained strong due to concerns around supply and the impact of higher crude oil prices. NYMEX natural gas prices increased 12% to average US$6.09 per mmbtu in 2004, up from US$5.44 per mmbtu in 2003 (2002 – US$3.25 per mmbtu). AECO natural gas prices increased 1% to average $6.43 per GJ in 2004, up from $6.35 per GJ in 2003 (2002 – $3.86 per GJ).

Revenue, before royalties

Product prices (1)	2004	2003	2002
Crude oil and NGLs ($/bbl)			
North America	**$ 33.16**	$ 29.40	$ 28.77
North Sea	**$ 51.37**	$ 42.00	$ 40.32
Offshore West Africa	**$ 49.05**	$ 36.47	$ 40.10
Company average	**$ 37.99**	$ 32.66	$ 31.22
Natural gas ($/mcf)			
North America	**$ 6.61**	$ 6.34	$ 3.79
North Sea	**$ 3.73**	$ 3.03	$ 2.75
Offshore West Africa	**$ 5.25**	$ 4.37	$ 4.82
Company average	**$ 6.50**	$ 6.21	$ 3.77
Percentage of revenue (excluding midstream revenue)			
Crude oil and NGLs	**54%**	50%	58%
Natural gas	**46%**	50%	42%

(1) Including transportation costs and excluding risk management activities.

Realized crude oil prices increased 16% to average $37.99 per bbl in 2004, up from $32.66 per bbl in 2003 (2002 – $31.22 per bbl). The increase in realized crude oil prices is a result of higher benchmark crude oil prices.

The Company's realized natural gas price increased 5% to average $6.50 per mcf in 2004, up from $6.21 per mcf in 2003 (2002 – $3.77 per mcf).

North America

North America realized crude oil prices increased 13% to average $33.16 per bbl in 2004, up from $29.40 per bbl in 2003 (2002 – $28.77 per bbl). The increase in the realized crude oil price is due mainly to higher world crude oil prices, partially offset by wider heavy crude oil differentials and the stronger Canadian dollar.

The Company continues to focus on its crude oil marketing strategy, which includes development of a blending strategy, supporting pipeline projects that will provide capacity to transport crude oil to new markets, and working with PADD II refiners to add incremental heavy crude oil conversion capacity. As part of an industry initiative to develop new blends of Western Canadian crude oils, the Company has access to blending capacity of up to 140 mbbl/d. The Company is contributing 123 mbbl/d of heavy crude oil blends to the Western Canadian Select ("WCS") stream, a new blend of up to 10 different crude oil streams. WCS resembles a Bow River type crude with distillation cuts approximating a natural heavy oil with premium quality asphalt characteristics. The new blend has an API of 19-22 degrees and is expected to grow, with the potential to become a new benchmark for North American markets in addition to WTI. The Company also continues to work with refiners to advance expansion of heavy crude oil conversion capacity, and is working with pipeline companies to develop new capacity to the Canadian west coast where crude cargos can be sold on a world-wide basis.

North America realized natural gas prices increased 4% to average $6.61 per mcf in 2004, up from $6.34 per mcf in 2003 (2002 – $3.79 per mcf). The increase in natural gas pricing is due to the concerns around supply and the impact of higher crude oil prices.

A comparison of the price received for the Company's North America production is as follows:

	2004	2003	2002
Wellhead price (1)			
Light crude oil and NGLs (C$/bbl)	**$ 45.90**	$ 37.59	$ 34.92
Pelican Lake crude oil (C$/bbl)	**$ 32.12**	$ 28.05	$ 27.56
Primary heavy crude oil (C$/bbl)	**$ 28.99**	$ 26.21	$ 27.06
Thermal heavy crude oil (C$/bbl)	**$ 29.00**	$ 25.56	$ 25.70
Natural gas (C$/mcf)	**$ 6.61**	$ 6.34	$ 3.79

(1) Including transportation costs and excluding risk management activities.

North Sea

North Sea realized crude oil prices increased 22% to average $51.37 per bbl in 2004, up from $42.00 per bbl in 2003 (2002 – $40.32 per bbl) due to higher world crude oil prices.

Offshore West Africa

Offshore West Africa realized crude oil prices increased 34% to average $49.05 per bbl in 2004, up from $36.47 per bbl in 2003 (2002 – $40.10 per bbl) due to higher world crude oil prices.

Analysis of changes in revenue, before royalties

($ millions)	2002	Changes due to Volumes	Changes due to Prices	Changes due to Other	2003	Changes due to Volumes	Changes due to Prices	Changes due to Other	2004
North America									
Crude oil and NGLs	$ 1,854	$ 55	$ 44	$ –	$ 1,953	**$ 342**	**$ 283**	**$ –**	**$ 2,578**
Natural gas	1,865	56	1,147	–	3,068	**207**	**126**	**–**	**3,401**
	3,719	111	1,191	–	5,021	**549**	**409**	**–**	**5,979**
North Sea									
Crude oil and NGLs	592	265	16	–	873	**123**	**227**	**–**	**1,223**
Natural gas	28	19	33	–	80	**5**	**9**	**–**	**94**
	620	284	49	–	953	**128**	**236**	**–**	**1,317**
Offshore West Africa									
Crude oil and NGLs	100	56	(15)	–	141	**13**	**54**	**–**	**208**
Natural gas	2	13	(1)	–	14	**(1)**	**1**	**–**	**14**
	102	69	(16)	–	155	**12**	**55**	**–**	**222**
Subtotal									
Crude oil and NGLs	2,546	376	45	–	2,967	**478**	**564**	**–**	**4,009**
Natural gas	1,895	88	1,179	–	3,162	**211**	**136**	**–**	**3,509**
	4,441	464	1,224	–	6,129	**689**	**700**	**–**	**7,518**
Midstream	52	–	–	9	61	**–**	**–**	**7**	**68**
Other	–	–	–	–	–	**–**	**–**	**1**	**1**
Intersegment eliminations (1)	(34)	–	–	(1)	(35)	**–**	**–**	**(5)**	**(40)**
Total	$ 4,459	$ 464	$ 1,224	$ 8	$ 6,155	**$ 689**	**$ 700**	**$ 3**	**$ 7,547**

(1) Eliminates internal transportation and electricity charges.

Revenue rose 23% to $7,547 million in 2004, up from $6,155 million in 2003 (2002 – $4,459 million). In 2004, 20% of the Company's crude oil and natural gas revenue was generated outside of North America, up from 18% in 2003 (2002 – 16%). North Sea accounted for 17% of revenue in 2004 and 16% in 2003 (2002 – 14%), and Offshore West Africa accounted for 3% of revenue in 2004 and 2% in 2003 (2002 – 2%).

The Company's production composition, before royalties, is as follows:

Daily production, before royalties

	2004	2003	2002
Crude oil and NGLs (bbl/d)			
North America	**206,225**	174,895	169,675
North Sea	**64,706**	56,869	38,876
Offshore West Africa	**11,558**	10,628	6,784
	282,489	242,392	215,335
Natural gas (mmcf/d)			
North America	**1,330**	1,245	1,204
North Sea	**50**	46	27
Offshore West Africa	**8**	8	1
	1,388	1,299	1,232
Total barrel of oil equivalent (boe/d)	**513,835**	458,814	420,722
Product mix			
Light crude oil and NGLs	**24%**	25%	21%
Pelican Lake crude oil	**4%**	5%	7%
Primary heavy crude oil	**19%**	15%	14%
Thermal heavy crude oil	**8%**	8%	9%
Natural gas	**45%**	47%	49%

Daily production, net of royalties

	2004	2003	2002
Crude oil and NGLs (bbl/d)			
North America	**180,011**	152,444	149,485
North Sea	**64,598**	56,928	36,654
Offshore West Africa	**11,221**	10,314	6,554
	255,830	219,686	192,693
Natural gas (mmcf/d)			
North America	**1,048**	976	949
North Sea	**50**	46	27
Offshore West Africa	**7**	8	1
	1,105	1,030	977
Total barrel of oil equivalent (boe/d)	**440,022**	391,361	355,611

Daily production and per barrel statistics are presented throughout the MD&A on a "before royalty" or "gross" basis. Production net of royalties is presented above for information purposes only.

The Company's business approach is to maintain large project inventories and production diversification among each of the commodities it produces; namely natural gas, light crude oil and NGLs, Pelican Lake crude oil, primary heavy crude oil and thermal heavy crude oil.

The Company achieved record levels of production on a barrel of oil equivalent basis in 2004. Production before royalties on a barrel of oil equivalent basis increased 12% to average 513,835 boe/d in 2004, up from 458,814 boe/d in 2003 (2002 – 420,722 boe/d). The production volumes increased as a result of the Company's successful capital expenditure program and the acquisition of certain resource properties in the Company's North America and North Sea segments. Total crude oil and NGLs production before royalties increased 17% or 40,097 bbl/d to average 282,489 bbl/d, up from 242,392 bbl/d in 2003 (2002 – 215,335 bbl/d). Crude oil and NGLs production before royalties in 2004 increased from the previous year in all segments and was in line with production guidance provided. Natural gas production before royalties continues to represent the Company's largest product offering, accounting for 45% of the Company's total production in 2004 compared to 47% of total production in 2003 (2002 – 49%). Natural gas production before royalties increased 7% or 89 mmcf/d to average 1,388 mmcf/d, up from 1,299 mmcf/d in 2003 (2002 – 1,232 mmcf/d). Natural gas production was in line with production guidance provided.

The Company expects annual production levels before royalties in 2005 to average 1,448 to 1,510 mmcf/d of natural gas and 307 to 335 mbbl/d of crude oil and NGLs. First quarter 2005 production guidance before royalties is 1,400 to 1,482 mmcf/d of natural gas and 269 to 290 mbbl/d of crude oil and NGLs.

North America

Crude oil and NGLs production before royalties in North America increased 18% or 31,330 bbl/d to average 206,225 bbl/d in 2004, up from 174,895 bbl/d in 2003 (2002 – 169,675 bbl/d) due to the development of the Primrose thermal crude oil project and accretive acquisitions.

North American natural gas production before royalties in 2004 increased 7% or 85 mmcf/d to average 1,330 mmcf/d, up from 1,245 mmcf/d in 2003 (2002 – 1,204 mmcf/d). North American production of natural gas increased as a result of organic growth and accretive property acquisitions. Production of natural gas was impacted by the shut in of 11 mmcf/d of natural gas in the Athabasca Wabiskaw-McMurray oil sands area effective July 1, 2004.

North Sea

Crude oil production before royalties from the North Sea increased 14% or 7,837 bbl/d to average 64,706 bbl/d in 2004, up from 56,869 bbl/d in 2003 (2002 – 38,876 bbl/d). The increase in production was due to the ongoing drilling, recompletion and waterflood optimization program at the Ninian and Murchison Fields and the acquisition of light crude oil producing properties in the Central North Sea in the third quarter of 2004. Crude oil production before royalties in the fourth quarter was down primarily due to an unplanned extended shutdown on the Ninian North Platform. The shutdown was required to repair a power turbine used to drive water injection resulting in a loss of pressure to the reservoir. Remedial work was completed in early 2005 and production is recovering.

Natural gas production before royalties in the North Sea increased 9% or 4 mmcf/d to average 50 mmcf/d in 2004, up from 46 mmcf/d in 2003 (2002 – 27 mmcf/d). The increase in production was due to the acquisition of properties in the Central North Sea in the third quarter of 2004 and the increased working interests acquired in the Banff Field during 2003. The increase was partially offset by the commencement of the natural gas reinjection program in the Banff Field in the fourth quarter of 2004. Despite some delays and production interruptions during commissioning, results to date are positive with full production benefit expected to commence during the second quarter of 2005. Natural gas production in the North Sea is expected to decline in 2005 due to the natural gas reinjection program in the Banff Field.

Offshore West Africa

Offshore West Africa crude oil production before royalties for the year ended December 31, 2004 increased 9% or 930 bbl/d to average 11,558 bbl/d, up from 10,628 bbl/d in 2003 (2002 – 6,784 bbl/d) due to the perforation of the upper zone of the East Espoir Field in the third quarter of 2003 and the completion of the fourth water injection well and two additional producing wells during 2003.

Natural gas production before royalties in Offshore West Africa remained constant at 8 mmcf/d in 2004 and 2003 (2002 – 1 mmcf/d).

Royalties

	2004	2003	2002
Crude oil and NGLs ($/bbl)			
North America	$ 4.21	$ 3.79	$ 3.42
North Sea	$ 0.08	$ (0.03)	$ 2.30
Offshore West Africa	$ 1.43	$ 1.08	$ 1.35
Company average	$ 3.16	$ 2.77	$ 3.16
Natural gas ($/mcf)			
North America	$ 1.40	$ 1.38	$ 0.80
North Sea	$ –	$ –	$ –
Offshore West Africa	$ 0.15	$ 0.13	$ 0.15
Company average	$ 1.35	$ 1.32	$ 0.78
Company average ($/boe)	$ 5.37	$ 5.20	$ 3.91
Percentage of revenue (1)			
Crude oil and NGLs	8%	9%	10%
Natural gas	21%	21%	21%
Boe	14%	15%	14%

(1) Including transportation costs and excluding risk management activities.

North America

Crude oil and NGLs royalties in North America increased to $4.21 per bbl, up from $3.79 per bbl in 2003 (2002 – $3.42 per bbl) due to higher benchmark crude oil prices.

Natural gas royalties in North America increased to $1.40 per mcf, up from $1.38 per mcf in 2003 (2002 – $0.80 per mcf). Natural gas royalties as a percentage of revenue fluctuate as a result of fluctuations in natural gas prices and the strong correlation of royalties to natural gas prices.

North Sea

North Sea crude oil royalties increased to $0.08 per bbl, up from a recovery of $(0.03) per bbl in 2003 (2002 – $2.30 per bbl).

North Sea government royalties on crude oil were eliminated effective January 1, 2003. The remaining North Sea royalty represents a gross overriding royalty on the Ninian Field. In 2003, the Company received a refund of royalties previously provided.

Offshore West Africa

Offshore West Africa crude oil royalties increased to $1.43 per bbl, up from $1.08 per bbl in 2003 (2002 – $1.35 per bbl) due to fluctuations in realized crude oil prices. Offshore West Africa production is governed by the terms of the Production Sharing Contract ("PSC"). Under the PSC, revenues are divided into cost recovery revenue and profit revenue. Cost recovery revenue allows the Company to recover the capital and operating costs carried by the Company on behalf of the Government State Oil Company. These revenues are reported as sales revenue. Profit revenue is allocated to the joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Government. The Government's share of revenue attributable to the Company's equity interest is reported as either royalty expense or current income tax expense in accordance with the PSC.

Production expense

	2004	2003	2002
Crude oil and NGLs ($/bbl)			
North America	**$ 8.94**	$ 9.14	$ 6.73
North Sea	**$ 14.03**	$ 14.07	$ 15.06
Offshore West Africa	**$ 7.59**	$ 8.68	$ 13.63
Company average	**$ 10.05**	$ 10.28	$ 8.45
Natural gas ($/mcf)			
North America	**$ 0.62**	$ 0.57	$ 0.55
North Sea	**$ 2.07**	$ 1.33	$ 1.53
Offshore West Africa	**$ 1.33**	$ 1.39	$ 1.81
Company average	**$ 0.67**	$ 0.60	$ 0.57
Company average ($/boe)	**$ 7.35**	$ 7.15	$ 5.99

Production expense increased to $7.35 per boe in 2004, up from $7.15 per boe in 2003 (2002 – $5.99 per boe). Crude oil and NGLs production expense decreased to $10.05 per bbl in 2004, down from $10.28 per bbl in 2003 (2002 – $8.45 per bbl). Natural gas production expense for the year 2004 increased to $0.67 per mcf, up from $0.60 per mcf in 2003 (2002 – $0.57 per mcf).

North America

North American crude oil and NGLs production expense decreased 2% to average $8.94 per bbl, down from $9.14 per bbl in 2003 (2002 – $6.73 per bbl). The decrease was primarily due to the impact of a lower steam oil ratio for the Company's thermal heavy crude oil operations, resulting in a lower cost per barrel for fuel used in the generation of steam.

North American natural gas production expense per mcf increased 9% to average $0.62 per mcf, up from $0.57 per mcf in 2003 (2002 – $0.55 per mcf). The increase is partly due to increased activity in the oil and gas sector in reaction to higher commodity prices, which resulted in higher production expense, especially as the labour market tightened, and partly due to increased production in certain areas such as Northeast British Columbia where the Company is incurring higher costs associated with third party processing and gathering. In addition, the cost of steel products increased in 2004 due to increased global demand.

North Sea

North Sea crude oil production expense decreased in 2004 to $14.03 per bbl, down from $14.07 per bbl in 2003 (2002 – $15.06 per bbl).

North Sea crude oil production expense varied on a per barrel basis due to the timing of maintenance work and the changes in production volumes on a relatively fixed cost base.

Offshore West Africa

Offshore West Africa crude oil production expense decreased to $7.59 per bbl, down from $8.68 per bbl in 2003 (2002 – $13.63 per bbl), resulting from production increases in the Espoir Field. The Espoir Field commenced operations in the first quarter of 2002.

Offshore West Africa crude oil production expenses are largely fixed in nature and therefore fluctuate on a per barrel basis from the comparable periods due to changes in production from the Espoir Field.

Midstream

($ millions)	2004	2003	2002
Revenue	**$ 68**	$ 61	$ 52
Production expense	**20**	15	14
Midstream cash flow	**48**	46	38
Depreciation	**7**	7	8
Segment earnings before taxes	**$ 41**	$ 39	$ 30

The Company's midstream assets consist of three crude oil pipeline systems and an 84-megawatt cogeneration plant at Primrose where the Company has a 50% working interest. Approximately 80% of the Company's heavy crude oil production was transported to the international mainline liquid pipelines via the 100% owned and operated ECHO Pipeline, the 62% owned and operated Pelican Lake Pipeline and the 15% owned Cold Lake Pipeline. The midstream pipeline assets allow the Company to transport its own production volumes at reduced costs compared to other transportation alternatives as well as earn third party revenue. This transportation control enhances the Company's ability to control the full range of costs associated with the development and marketing of its heavy crude oil.

Revenue from the midstream assets increased 11% to $68 million, up from $61 million in 2003 (2002 – $52 million). The increase in revenue, operating cash flow and segment earnings before taxes was due to the expansion of the ECHO Pipeline. The expansion of the ECHO Pipeline was completed in October 2003 and increased capacity to 72 mbbl/d from 58 mbbl/d.

Depletion, depreciation and amortization (2)

($ millions, except per boe amounts)		2004		2003(1)		2002(1)
North America	$	**1,444**	$	1,209	$	1,022
North Sea		**265**		252		188
Offshore West Africa		**53**		41		80
Expense	$	**1,762**	$	1,502	$	1,290
$/boe	$	**9.37**	$	8.96	$	8.40

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) DD&A excludes depreciation on midstream assets.

Depletion, depreciation and amortization ("DD&A") increased in total and per boe to $1,762 million or $9.37 per boe, up from $1,502 million or $8.96 per boe in 2003 (2002 – $1,290 million or $8.40 per boe). The increase in DD&A was due to higher finding and development costs associated with natural gas exploration in North America, the allocation of the acquisition costs associated with recent acquisitions, the fair value of future abandonment costs associated with the acquisition of additional properties in the North Sea, and higher costs to develop the Company's proved undeveloped reserves. In 2003, DD&A included the write-off of $12 million of costs associated with the Company's exploration activity in offshore France. In 2002, DD&A included the write-off of $51 million as a result of the Company's decision to exit from its interests in Block 19, Angola, and from the Aje Field, Nigeria.

Asset retirement obligation accretion

($ millions, except per boe amounts)		2004		2003(1)		2002(1)
North America	$	**28**	$	26	$	20
North Sea		**22**		36		48
Offshore West Africa		**1**		–		–
Expense	$	**51**	$	62	$	68
$/boe	$	**0.27**	$	0.37	$	0.44

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

Accretion expense is the increase in the carrying amount of the asset retirement obligation due to the passage of time.

Administration expense

($ millions, except per boe amounts)		2004		2003		2002
Gross cost	$	**315**	$	262	$	147
$/boe	$	**1.68**	$	1.57	$	0.96
Net expense	$	**115**	$	87	$	61
$/boe	$	**0.61**	$	0.52	$	0.40

Gross administration expense increased to $1.68 per boe, up from $1.57 per boe in 2003 (2002 – $0.96 per boe) mainly due to higher staffing levels associated with the Company's expanding asset base and costs associated with the Horizon Project. Gross administration expense also increased as a result of higher costs related to the assumption of operatorship of certain fields in the North Sea in 2003. Net administration expense, after operator recoveries and capitalized overhead relating to exploration and development in the North Sea and Offshore West Africa as well as the Horizon Project, increased to $0.61 per boe in 2004, up from $0.52 per boe in 2003 (2002 – $0.40 per boe).

Stock-based compensation

($ millions, except per boe amounts)		2004		2003		2002
Stock option plan	$	249	$	200	$	–
Share bonus plan		10		–		–
Stock-based compensation expense	$	259	$	200	$	–
$/boe	$	1.37	$	1.20	$	–

The Company's Stock Option Plan (the "Option Plan") provides current employees, officers and directors (the "option holders") with the right to elect to receive common shares or a direct cash payment in exchange for options surrendered. The Option Plan balances the need for a long-term compensation program to retain employees with reducing the impact of dilution on current Shareholders and the reporting of the expense associated with stock options. Transparency of the cost of the Option Plan is increased since changes in the fair value of outstanding stock options are expensed. The cash payment feature provides option holders with substantially the same benefits and allows them to realize the value of their options through a simplified administration process.

The Company has recorded a liability at December 31, 2004 of $323 million compared to $171 million at December 31, 2003 for expected cash settlements of stock options based on the fair value of the outstanding stock options (the difference between the exercise price of the stock options and the market price of the Company's common shares). The liability is revalued to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings.

The stock-based compensation expense relating to the Company's Option Plan in 2004 is $249 million ($168 million after tax), up from $200 million ($136 million after tax) in 2003.

In 2004, the Company paid $80 million for stock options surrendered for cash settlement compared to $31 million in 2003.

The Share Bonus Plan incorporates share ownership in the Company by its employees without the granting of stock options or the dilution of current Shareholders. Under the plan, a cash bonus may be awarded based on the Company's and the employee's performance and subsequently used by a trustee to acquire common shares of the Company. The common shares vest to the employee over a three-year period provided the employee does not leave the employment of the Company. If the employee leaves the employment of the Company, the unvested common shares are forfeited under the terms of the plan. In 2004, the Company recognized $10 million ($6 million after tax) of compensation expense under the Share Bonus Plan.

Interest expense

($ millions, except per boe amounts and interest rates)		2004		2003(1)		2002(1)
Interest expense	$	189	$	201	$	203
$/boe	$	1.01	$	1.20	$	1.26
Average effective interest rate		5.2%		5.8%		5.5%

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

Interest expense decreased to $189 million in 2004, down from $201 million in 2003 (2002 – $203 million) due mainly to a lower average effective interest rate of 5.2%, down from 5.8% in 2003 (2002 – 5.5%). In addition, the strengthening Canadian dollar reduced the Canadian equivalent interest expense on the Company's US dollar denominated debt. The Company continues to benefit from the lower short-term interest rates as its fixed-rate debt accounts for only 43% of total debt outstanding after interest rates swaps (see note 12 to the consolidated financial statements) as at December 31, 2004 (2003 – 32%, 2002 – 40%).

Interest expense was impacted by the Company prospectively adopting the Canadian Institute of Chartered Accountants' ("CICA") Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments." As a result of the adoption of this accounting guideline, $32 million of realized gains on certain of its fixed to floating interest rate swaps are included in risk management activities in 2004 (2003 – $35 million, 2002 – $34 million). Interest expense decreased on a total and boe basis in 2004 from 2003 mainly due to lower borrowing rates.

Risk management activities

On January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Financial instruments that do not qualify as hedges under the Guideline or are not designated as hedges are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading or speculative purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on interest rate contracts not designated as hedges are included in risk management activities.

The Company enters into cross currency swap agreements to manage its fixed to floating interest rate mix on long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under other long-term assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Adoption of this Guideline and EIC 128 had the following effects on the Company's consolidated financial statements:

($ millions)		2004		2003		2002
Realized loss (gain)						
Crude oil and NGLs financial instruments	$	**501**	$	95	$	114
Natural gas financial instruments		**5**		88		3
Interest rate swaps		**(32)**		(35)		(34)
	$	**474**	$	148	$	83
Unrealized loss (gain)						
Crude oil and NGLs financial instruments	$	**(47)**	$	–	$	–
Natural gas financial instruments		**–**		–		–
Interest rate swaps		**7**		–		–
	$	**(40)**	$	–	$	–
Total	$	**434**	$	148	$	83

The effect of the realized loss from crude oil and NGLs and natural gas financial instruments was to reduce the Company's average realized prices as follows:

		2004		2003		2002
Crude oil and NGLs ($/bbl)	$	**4.85**	$	1.07	$	1.46
Natural gas ($/mcf)	$	**0.01**	$	0.19	$	0.01

The effect of the realized gain on interest rate swaps on the Company's interest expense was:

($ millions, except interest rates)		2004		2003(1)		2002(1)
Interest expense as per the financial statements	$	**189**	$	201	$	203
Less: realized risk management gain		**(32)**		(35)		(34)
	$	**157**	$	166	$	169
Average effective interest rate		**4.4%**		4.8%		4.6%

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

Foreign exchange

($ millions)	2004	2003(1)	2002(1)
Realized foreign exchange loss	$ 3	$ 8	$ 4
Unrealized foreign exchange gain	(94)	(343)	(36)
Total	$ (91)	$ (335)	$ (32)

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

The majority of the unrealized foreign exchange gain is related to the fluctuation of the Canadian dollar in relation to the US dollar. The Canadian dollar ended the year 2004 at US$0.8308 compared to US$0.7738 at December 31, 2003 (December 31, 2002 – US$0.6331).

The majority of the Company's borrowings are denominated in US dollars. At December 31, 2004, the Company's US dollar denominated debt amounted to US$2,969 million compared to US$2,045 million in 2003 (2002 – US$2,048 million). US dollar denominated debt represented 77% of total debt outstanding at December 31, 2004 (2003 – 85%, 2002 – 77%). Due to the higher proportion of US dollar denominated debt outstanding, the Company's net earnings are more sensitive to fluctuations in the Canadian dollar.

In order to mitigate a portion of the volatility associated with the Canadian dollar, the Company has designated certain US dollar denominated debt as a hedge against its net investment in US dollar based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

The Company's realized product prices are sensitive to currency exchange rates. Recent increases in the value of the Canadian dollar in relation to the US dollar had a negative impact on the Company's commodity prices realized (see Sensitivity Analysis).

Taxes

($ millions, except income tax rates)	2004	2003	2002
Taxes other than income tax			
Current	$ 210	$ 116	$ 53
Deferred	(45)	(9)	10
Total	$ 165	$ 107	$ 63
Current income tax			
North America – Current income tax	$ 89	$ 43	$ –
North America – Large Corporations Tax	11	16	21
North Sea	2	23	(19)
Offshore West Africa	13	10	6
Other	1	–	–
Total	$ 116	$ 92	$ 8
Future income tax (1)	$ 474	$ 338	$ 375
Effective income tax rate (1)	29.6%	23.5%	41.6%

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

Taxes other than income tax consist of current and deferred petroleum revenue tax ("PRT"), other international taxes and provincial capital taxes and surcharges. PRT is charged on certain fields in the North Sea at the rate of 50% of net operating income after certain deductions including abandonment expenditures. Taxes other than income tax increased to $165 million or $0.88 per boe in 2004, up from $107 million or $0.64 per boe in 2003 (2002 – $63 million or $0.41 per boe). The increase in taxes other than income tax was mainly due to the higher netback earned in the North Sea as a result of higher crude oil prices and higher production levels. North Sea PRT accounts for $145 million or $0.77 per boe in 2004 compared to $97 million or $0.58 per boe in 2003 (2002 – $51 million or $0.33 per boe).

Taxable income from the conventional crude oil and natural gas business in Canada is generated by partnerships and the related income taxes will be payable in the following year. Current income taxes have been provided on the basis of the corporate structure and available income tax deductions and will vary depending upon the amount of capital expenditures incurred in Canada and the way it is deployed. No current income tax provision was required for North America in 2002.

The Company is liable for the payment of Federal Large Corporations Tax ("LCT"). LCT decreased to $11 million or $0.09 per boe from $16 million or $0.14 per boe (2002 – $21 million or $0.11 per boe) as a result of the Company being taxable and a partial offset available in the calculation of the Federal corporate surtax. In addition, the LCT rate was reduced from 0.225% to 0.2% in 2004 as part of the phased elimination of LCT over five years.

It is anticipated that, based on the current availability of approximately $4.5 billion of tax pools in Canada at the end of 2004 and current commodity strip prices, the Company will be cash taxable in Canada in 2005 in the amount of $200 million to $300 million.

Current income tax in the North Sea decreased to $2 million or $0.01 per boe, down from $23 million or $0.14 per boe in 2003 (2002 – recovery of $19 million or $0.13 per boe). The decrease in the current income tax expense was due to tax pools acquired in the recent acquisition being immediately deductible. The North Sea current income tax was also impacted by changes in the tax rules in the North Sea. In 2002, a supplementary charge of 10% on profits from UK North Sea crude oil and natural gas production was introduced. The North Sea supplementary charge, which took effect April 17, 2002, is in addition to the corporate income tax rate of 30% and excludes any deduction for financing costs. In addition, the first year capital allowance rate for plant and machinery expenditures was increased to 100% from the previous rate of 25%.

The Company's future income tax provision for 2004 increased to $474 million ($2.53 per boe), up from $338 million ($2.02 per boe) in 2003 (2002 – $375 million or $2.45 per boe). In 2004 the North America future income tax liability was reduced by $66 million as a result of a reduction in the Alberta corporate income tax rate (2003 – $31 million, 2002 – $21 million). In 2003, the Federal Government introduced legislation to reduce the corporate income tax rate on income from resource activities over a five-year period starting January 1, 2003, bringing the resource industry in line with the general corporate income tax rate. As part of the corporate income tax rate reduction, the legislation also provides for the elimination of the existing 25% resource allowance and the introduction of a deduction for actual provincial and other crown royalties paid. As a result of the Federal tax rate reductions, the future income tax liability in North America was decreased by $247 million in 2003.

In 2002, the future income tax liability in the North Sea was increased by $34 million as a result of the introduction of a 10% supplementary charge on profits from North Sea crude oil and natural gas production.

The following table shows the effect of non-recurring benefits on income taxes:

($ millions, except income tax rates)	2004	2003	2002
Income tax as reported			
Current income tax	$ 116	$ 92	$ 8
Future income tax expense[(1)]	474	338	375
	590	430	383
Alberta corporate tax rate reduction	66	31	21
Federal corporate tax rate reduction	–	247	–
UK supplementary tax on profits	–	–	(34)
Total	$ 656	$ 708	$ 370
Expected effective income tax rate	32.9%	38.6%	40.2%

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

Capital expenditures

($ millions)	2004	2003	2002
Expenditures on property, plant and equipment			
Net property acquisitions [(1)]	$ 1,835	$ 336	$ 2,833
Land acquisition and retention	120	154	114
Seismic evaluations	89	77	63
Well drilling, completion and equipping	1,394	1,194	626
Pipeline and production facilities	821	522	292
Total net reserve replacement expenditures	4,259	2,283	3,928
Horizon Oil Sands Project	291	152	68
Midstream	16	11	20
Abandonments	32	40	43
Head office	35	20	10
Total net capital expenditures	$ 4,633	$ 2,506	$ 4,069
By segment			
North America	$ 3,355	$ 1,769	$ 3,420
North Sea	608	338	323
Offshore West Africa	296	176	185
Horizon Project	291	152	68
Midstream	16	11	20
Abandonments	32	40	43
Head office	35	20	10
Total	$ 4,633	$ 2,506	$ 4,069

(1) Includes Business Combinations.

The Company's strategy is focused on building a diversified asset base that is balanced between various products. The capital expenditures program continues to reflect this strategy.

In 2004, capital expenditures were $4,633 million, including the acquisition of Petrovera, compared to $2,506 million in 2003 (2002 – $4,069 million including the acquisition of Rio Alto). The increase in capital expenditures was a result of property acquisitions made in the North America and North Sea segments. The Company continues to make significant progress on its larger, future-growth projects while maintaining its focus on existing assets.

The Company's drilling activity decreased 19% with the drilling of 1,449 net wells compared to 1,793 net wells drilled in 2003 (2002 – 900 net wells). The Company drilled 689 net natural gas wells, down 11% from the 777 net wells in 2003 (2002 – 162 net wells) and 328 net crude oil wells, down 28% from the 458 net wells in 2003 (2002 – 264 net wells). In addition, during 2004 the Company drilled 336 net stratigraphic test/service wells primarily on the oil sands leases in the Horizon Project and in the Northern Plains core region, down 24% from the 440 net wells in 2003 (2002 – 447 net wells), and 96 net wells that were dry and abandoned, down 19% from the 118 net wells in 2003 (2002 – 27 net wells). The total number of wells drilled decreased from the prior year due to the reallocation of capital resulting from the strategic acquisitions completed in 2004. The Company achieved an overall success rate of 91%, excluding stratigraphic test and service wells. These excellent results reflect the disciplined approach that the Company takes in its exploitation and development programs and the strength of its asset base.

North America

North America accounted for 80% of the total capital expenditures in 2004 compared to 79% in 2003 (2002 – 86%).

In 2004, the Company drilled 689 net natural gas wells, including 163 net wells in the Northern Plains core region, 221 net wells in the Southern Plains core region targeting shallow gas, 138 net wells in Northwest Alberta and 167 net wells in Northeast British Columbia. The Company also drilled 317 net crude oil wells in 2004. These wells were concentrated in the Company's Nothern Plains crude oil region where 238 net heavy crude oil wells were drilled. Included in this figure were 58 net high-pressure horizontal thermal crude oil wells that were drilled and completed at Primrose as part of the 2004 development strategy of the area.

As part of the development of the Company's heavy crude oil resources, the Company is continuing with its Primrose thermal project, which includes the Primrose North expansion project and drilling additional wells in the Primrose South project to augment existing production. At Primrose South, production was commissioned from the two new phases that commenced construction in 2003. The Primrose North expansion continues to be on track and on budget with total capital expenditures of approximately $300 million expected to be incurred, leading to first oil of 30 mbbl/d in 2006.

Late in the third quarter, the Company filed a public disclosure document for regulatory approval of its Primrose East project, a new facility located about 15 kilometres from its existing Primrose South steam plant and 25 kilometres from its Wolf Lake central processing facility. Once completed, Primrose East will be fully integrated with existing operations at Wolf Lake, Primrose South and Primrose North. The Company currently expects to complete its regulatory application by late 2005 with a regulatory decision expected in late 2006.

The Pelican Lake enhanced crude oil recovery project continues on track. The waterflood has provided initial production increases as expected and has shown positive waterflood response. The waterflood project will be expanded in 2005 and the Company plans to enhance the process by use of a polymer flood. The polymer flood pilot will commence during 2005 with three injectors and five producers.

In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as Petrovera, for $471 million. Strategically, the acquisition fit with the Company's objective of dominating its core regions and related infrastructure. The Company achieved cost reductions through synergies with its existing facilities, including additional throughput in its 100% owned ECHO Pipeline. The acquisition is included in the results of operations commencing February 2004.

In the second quarter of 2004, the Company completed the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta for $280 million. These properties include a further ownership interest in the Ladyfern natural gas field. In addition, the Company acquired undeveloped pools with significant natural gas potential in deeper zones and will add a new exploration base in the Alberta Foothills.

In the fourth quarter of 2004, the Company completed the acquisition of certain resource properties located in Alberta, British Columbia and Saskatchewan for $703 million. The acquisition also includes over 510,000 net acres of unproven land. The acquisition has been included in operations effective December 2004. The acquisition fits the Company's strategy of dominating its core regions and related infrastructure, as the vast majority of the properties acquired are located within its core regions. The acquisition extends the Company's Northern Plains core region into the light crude oil operating area of Dawson.

During the fourth quarter, the Company increased capital spending levels directed toward natural gas drilling in an effort to reduce pressures of a tight 2005 winter drilling season by starting earlier. This effort included a detailed and sequential drilling program that facilitated the procurement of better drilling rigs and crews for the winter season, both of which are an integral part of cost control. Certain portions of the drilling program were delayed due to warmer than expected weather through mid-December; however, the Company still expects to complete the majority of its plan.

Midstream
The Cold Lake Pipeline Limited Partnership, in which the Company has a 15% working interest, completed the construction of new facilities to allow shipment of up to 60,000 bbl/d of DilSynBit product. The new DilSynBit product will include light synthetic oil as a blending component to dilute the heavy, tar-like Cold Lake bitumen. The DilSynBit project will involve construction of two 80,000 barrel storage tanks, pumping facilities and metering equipment on the Cold Lake system.

Horizon
The third phase of the front-end engineering for the Horizon Project, Engineering Design Specification ("EDS"), was completed and ongoing detail work continues. The EDS provided sufficient definition for a lump sum inquiry for the detailed Engineering, Procurement and Construction ("EPC") of the various project components. The EDS also provided a detailed cost estimate and the basis upon which management made the final recommendation to the Board of Directors for sanction of the Horizon Project. The Company received regulatory approvals from the Alberta Energy and Utilities Board as well as the Alberta Provincial Cabinet and the Federal Cabinet in the first quarter of 2004. In the fourth quarter, site preparation work continued as well as work on the construction of onsite access roads, camps and the installation of deep underground facilities such as electrical, natural gas, water and sewage. In addition, clarification of bid documents occurred, resulting in the Company being able to obtain approximately 68% of Phase 1 costs on a fixed cost basis. The current estimate for Phase 1 construction costs now totals approximately $6.8 billion, including a contingency reserve of $700 million. The total cost for all three phases of the Horizon Project is now expected to be approximately $10.8 billion.

On February, 9, 2005, the Board of Directors unanimously authorized management to proceed with Phase 1 of the Horizon Project.

North Sea
The Company continued with its planned program of infill drilling, recompletions, workovers and waterflood optimizations. During 2004, the Company commenced development drilling of the Lyell Field and the infill drilling program at the Ninian Field continued. In addition, one production and one injection well were completed at the Columba B terrace, and the Playfair well was completed in the fourth quarter with a production rate of 5 mbbl/d and sufficient associated natural gas to provide the Murchison Platform energy needs, thereby reducing production costs.

During the third quarter of 2004, the Company acquired certain light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma Fields) and B-Block (Balmoral, Stirling and Glamis Fields), together with associated production facilities, including a fixed platform Floating Production Vessel ("FPV") and adjacent exploration acreage. The Company equity interests in the producing fields acquired are:

T-Block	Tiffany, Toni and Thelma	100.00%
B-Block	Balmoral	70.20%
	Glamis	75.29%
	Stirling	68.68%

The Company continued with the implementation of the natural gas reinjection project at the Banff Field in the Central North Sea, with reinjection commencing in November 2004. The project is expected to increase the overall reservoir recovery of crude oil, but will result in reductions in natural gas volumes.

Offshore West Africa
Offshore West Africa capital expenditures include the development of the Baobab Field where drilling is ongoing. To date, production testing on four producer wells has met or exceeded expectations. In addition, the Floating Production, Storage and Offtake Vessel ("FPSO") has been completed and is now moored on location. During the fourth quarter of 2004, the Acajou North exploration well was drilled to delineate the extent of the previously drilled Acajou discovery. The result of this well did not yield sufficient hydrocarbons to merit a stand alone development at Acajou. However, this field is being evaluated for future tie-back to East Espoir. At Zaizou, an exploration well spudded late in the fourth quarter was unsuccessful and the data obtained from this well is currently being used to trace the pattern of oil migration in the area to help identify future exploration targets.

The planned development of the nearby West Espoir Field was sanctioned by partners with various components out for bid. The development is progressing on schedule and is expected to commence production in mid 2006 through existing FPSO facilities.

Finally, additional review of seismic and geological data on Block 16 located offshore Angola indicates that while significant upside remains a possibility, its risk level is outside the normal operating parameters of the Company. As a result, the Company continues to evaluate alternatives for its holdings in the Block.

Liquidity and capital resources

($ millions, except ratios)	2004	2003 (1)	2002 (1)
Working capital deficit (2)	**$ 652**	$ 505	$ 14
Long-term debt	**$ 3,538**	$ 2,748	$ 4,200
Shareholders' equity			
Share capital	**$ 2,408**	$ 2,353	$ 2,304
Retained earnings	**4,922**	3,650	2,424
Foreign currency translation adjustment	**(6)**	3	26
Total	**$ 7,324**	$ 6,006	$ 4,754
Debt to cash flow (2)(3)	**1.0x**	0.9x	1.9x
Debt to EBITDA (2)(3)	**0.9x**	0.8x	1.7x
Debt to book capitalization (2)	**33.8%**	32.8%	47.1%
Debt to market capitalization (2)	**21.4%**	25.1%	40.3%
After tax return on average common shareholders' equity (3)	**21.4%**	25.6%	13.0%
After tax return on average capital employed (2)(3)	**15.3%**	17.1%	8.8%

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) Includes current portion of long-term debt.

(3) Based on trailing 12-month activity.

At December 31, 2004, the working capital deficit amounted to $652 million and includes the current portion of other long-term liabilities of $260 million, consisting of stock based compensation of $243 million and the mark to market valuation of certain Risk Management financial derivative instruments of $17 million. The settlement of the stock-based compensation liability is dependant upon the surrender of vested stock options for cash settlement by employees and the value of the Company's share price at the time of surrender. The settlement of the Risk Management financial derivative instruments is primarily dependant upon the underlying crude oil and natural gas prices at the time of settlement of the financial derivative instrument, as compared to the value at December 31, 2004.

The Company is committed to maintaining its strong financial position throughout construction of the Horizon Project. In 2004, strong operational results and strong commodity prices enabled the Company to maintain debt levels at 33.8% of book capitalization. The Company has built the necessary financial capacity to complete the Horizon Project while at the same time not compromising delivery of low-risk conventional oil and natural gas growth opportunities. The financing of the first phase of the Horizon Project development will be guided by the competing principles of retaining as much direct ownership interest as possible while maintaining a strong balance sheet. Existing proved development projects, which have largely been funded prior to December 31, 2004, such as Baobab, Primrose and West Espoir provide identified growth in production volumes in 2005 and 2006, and will generate incremental free cash flows during the period 2005 to 2008 with which to finance the Horizon Project.

In January 2005, the Board of Directors of the Company authorized an expanded hedging program for the Company in an effort to reduce the risk of volatility in commodity price markets and to underpin the Company's cash flow through the Horizon Project construction period. This expanded program allows for up to 75% of the near 12 months estimated production, up to 50% of the following 13 to 24 months estimated production and up to 25% of production expected in months 25 to 48 to be hedged. This revised hedging program allows the Company to have greater stability in its free cash flow and enhances the Company's financial flexibility during the Horizon Project construction years. The Company currently has collar hedges covering approximately 71% and 45% of estimated 2005 and 2006 crude oil production respectively. Similarly, approximately 67% and 35% of estimated 2005 and 2006 natural gas production has been hedged. The Company may also look to offload capital commitments through the acceptance of complementary business partners, or potentially, project joint venture partners.

Long-term debt

Long-term debt at December 31, 2004, increased $790 million from the prior year. The debt to EBITDA ratio increased to 0.9x and the debt to book capitalization increased to 33.8% compared to a debt to EBITDA ratio of 0.8x and a debt to book capitalization of 32.8% in 2003. These ratios are currently below the Company's guidelines for balance sheet management of debt to EBITDA of 1.5x to 2.0x and debt to book capitalization of 40% to 45%.

At December 31, 2004, the Company had:

- $2.8 billion of available unused bank credit facilities;
- A fixed / floating interest rate mix of 43% / 57%;
- 77% of borrowings denominated in US dollars; and
- 85% of total long-term debt as non-bank based borrowing with a weighted average maturity of 16 years.

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014.

The Company filed a short form prospectus in May 2003 that allows for the issue of up to US$2 billion of debt securities in the United States until June 2005. Currently the Company has US$1.3 billion remaining under the $2 billion shelf prospectus. If issued, these securities will bear interest as determined at the date of issuance. In addition, the Company maintains a shelf prospectus in Canada for the offering of up to $1 billion of medium-term notes in Canada. If issued, these securities will bear interest as determined at the date of issuance.

Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in the fixed to floating interest rate mix.

As at December 31, 2004, the Company had unsecured bank credit facilities of $3,425 million compared to $1,925 million at the close of 2003 (2002 – $2,275 million).

In December 2004, the Company executed a $1,500 million, 5-year revolving credit facility, with three, one-year extension options.

The ratings of the Company's debt securities and its relationships with principal banks are extremely important to the Company as it continues to expand and grow. Hence, the Company's management will continually undertake to maintain a strong balance sheet and financial position. The Company's debt securities are rated "Baa1" by Moody's Investor Services Inc., "BBB+" by Standard & Poors Corporation and "BBB(high)" by Dominion Bond Rating Services Limited.

Share capital

Shareholders of the Company approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004.

The Company is authorized to issue an unlimited number of common shares. As at December 31, 2004, there were 268,181,000 common shares outstanding. As at February 18, 2005 there were 268,221,000 common shares outstanding. In addition, the Company is authorized to issue 200,000 Class 1 preferred shares. There were no preferred shares outstanding during these periods.

During 2004, the Company issued 1,591,000 common shares from the exercise of stock options for proceeds of $24 million.

During 2003, the Company issued 5,381,000 common shares from the exercise of stock options for proceeds of $89 million.

In 2002, the Company issued 20 million common shares at an attributed value of $522 million as part of the consideration to acquire Rio Alto. A further 5,046,000 common shares were issued from the exercise of stock options throughout 2002 for proceeds of $82 million.

In January 2005, the Company renewed its Normal Course Issuer Bid allowing it to purchase up to 13,409,006 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006.

As at December 31, 2004, the Company had purchased 873,400 common shares for a total cost of $33 million at an average purchase price of $38.01 per common share pursuant to a Normal Course Issuer Bid that has been in place since January 24, 2004.

The Company declared dividends on common shares in the amount of $107 million or $0.40 per common share in 2004, up from $81 million or $0.30 per common share in 2003 (2002 – $64 million, $0.25 per common share).

In February 2005, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.45 per common share for 2005. The 12.5% increase recognizes the stability of the Company's cash flow and provides a return to Shareholders. This is the fifth consecutive year in which the Company has paid dividends and the fourth consecutive year of an increase in the distribution paid to its Shareholders. In February 2004, the Company's Board of Directors approved an increase in the annual dividend paid by the Company to $0.40 per common share in 2004, up from the previous level of $0.30 per common share.

Commitments and off balance sheet arrangements

In the normal course of business, the Company has entered into various contractual arrangements and commitments that will have an impact on the Company's future operations. These contractual obligations and commitments relate primarily to debt repayments, operating leases relating to office space and offshore production and storage vessels, firm commitments for gathering, processing and transmission services. The following table summarizes the Company's commitments as at December 31, 2004:

($ millions)	2005	2006	2007	2008	2009	Thereafter
Natural gas transportation	$ 194	$ 147	$ 100	$ 78	$ 37	$ 168
Crude oil transportation and pipeline	$ 11	$ 9	$ 11	$ 12	$ 13	$ 154
Offshore equipment operating lease	$ 110	$ 48	$ 48	$ 48	$ 48	$ 184
Baobab Project	$ 99	$ –	$ –	$ –	$ –	$ –
Offshore drilling and other	$ 125	$ 8	$ –	$ –	$ –	$ –
Electricity	$ 26	$ 28	$ 20	$ 13	$ 8	$ 34
Office lease	$ 21	$ 21	$ 22	$ 23	$ 24	$ 30
Processing	$ 5	$ 2	$ –	$ –	$ –	$ –
Horizon Project	$ 99	$ –	$ –	$ –	$ –	$ –
Long-term debt	$ 194	$ –	$ 162	$ 37	$ 69	$ 2,713

Subsequent event

On February 9, 2005, the Company's Board of Directors unanimously authorized the Company to proceed with Phase 1 of the Horizon Oil Sands Project. The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to begin at 110,000 bbl/d of 34° API light sweet, synthetic crude oil ("SCO"). Phase 2 would increase production to 155,000 bbl/d of SCO. Phase 3 would further increase production to 232,000 bbl/d of SCO. Total expected capital costs for all three phases of development are estimated at $10.8 billion. Capital costs for the first phase of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008, respectively.

Oil and natural gas reserves

Canadian Natural retains qualified independent reserve evaluators, Sproule Associates Limited ("Sproule"), and Ryder Scott Company ("Ryder Scott"), to evaluate 100% of the Company's proved and probable oil and natural gas reserves and prepare Evaluation Reports on the Company's total reserves. Sproule evaluated the North American assets and Ryder Scott evaluated the international assets and a portion of the North American assets. Canadian Natural has been granted an exemption from the National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") which prescribes the standards for the preparation and disclosure of reserves and related information for companies listed in Canada. This exemption allows the Company to substitute United States Securities and Exchange Commission ("SEC") requirements for certain disclosures required under NI 51-101. The primary difference between the two standards is the additional requirement under NI 51-101 to disclose proved and probable reserves and future net revenues using forecast prices and costs. Canadian Natural has elected to disclose proved reserves using constant prices and costs as mandated by the SEC and has also provided proved and probable reserves under the same parameters as voluntary additional information. Another difference between the two standards is in the definition of proved reserves; however, as discussed in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), the standards which NI 51-101 employs, the difference in estimated proved reserves based on constant pricing and costs between the two standards is not material.

Canadian Natural has significant oil reserves that are considered heavy with a gravity of less than 20 degrees. Heavy crude oil sells at a discount to light crude oil using the benchmark West Texas Intermediate, which has an API gravity of approximately 40 degrees, because it requires upgrading before it can be processed by conventional refineries. There is a finite capacity for upgrading in North America, which is often reached when heavy crude oil from other countries enters the North American market. Heavy crude oil requires blending with condensate or light synthetic crude oil ("diluent") in order for it to be transported in a pipeline. During the winter, heavy crude oil requires a higher proportion of diluent because of the cold temperatures. Heavy crude oil is also processed into asphalt, which is typically in demand during the spring to fall paving months.

As a result of these factors, prices for heavy crude oil are historically low in December. Exacerbating this trend was reduced demand for heavy crude oil due to refinery turnarounds and other operational issues. During 2004 the price of heavy crude oil averaged US$30.40 per barrel but on December 31, 2004, the date the Company's oil and natural gas reserves were evaluated, the calculated price of Hardisty 12 degree API heavy crude oil was less. As a result, 30 mmbbl of net proved heavy crude oil reserves did not produce positive cash flow and, in accordance with SEC regulations, were debooked. Notwithstanding the economics at December 31, 2004, the current price of heavy crude oil has returned to a price sufficient to return the reserves subtracted by negative revision to the proved reserve category.

Horizon oil sands mining reserves are not part of Canadian Natural's year-end reserves disclosure. Horizon reserves were evaluated as at February 9, 2005. Gilbert Laustsen Jung Associates Ltd. ("GLJ"), an independent qualified reserves evaluator, was retained by the Reserves Committee of Canadian Natural's Board of Directors to evaluate reserves associated with the Horizon Project incorporating both the mining and upgrading projects. These reserves were evaluated under SEC Industry Guide 7.

The Board of Directors of the Company has a Reserves Committee, which has met with and carried out independent due diligence procedures with each of Sproule, Ryder Scott and GLJ as to the Company's reserves.

Additional reserve disclosure is contained in the supplementary oil and gas information and the Company's Annual Information Form.

Risks and uncertainties

The Company is exposed to several operational risks inherent in exploring, developing, producing and marketing crude oil and natural gas. These inherent risks include: economic risk of finding and producing reserves at a reasonable cost; financial risk of marketing reserves at an acceptable price given current market conditions; cost of capital risk associated with securing the needed capital to carry out the Company's operations; risk of fluctuating foreign exchange rates; risk of carrying out operations with minimal environmental impact; risk of governmental policies, social instability or other political, economic or diplomatic developments in its international operations; and credit risk of non-payment for sales contracts or non-performance by counterparties to contracts.

The Company uses a variety of means to help minimize these risks. The Company maintains a comprehensive insurance program to reduce risk to an acceptable level and to protect it against significant losses. Operational control is enhanced by focusing efforts on large core regions with high working interests and by assuming operatorship of all key facilities. Product mix is diversified, ranging from the production of natural gas to the production of crude oil of various grades. The Company believes this diversification reduces price risk when compared with over-leverage to one commodity. Sales of crude oil and natural gas are aimed at various markets to ensure that undue exposure to any one market does not exist. Financial instruments are utilized to help ensure targets are met and to manage commodity prices, foreign currency rates and interest rate exposure. The Company minimizes credit risks by entering into sales contracts and financial derivatives with only highly rated entities and financial institutions. In addition, the Company reviews its exposure to individual companies on a regular basis, and where appropriate ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default.

The Company's current position with respect to its financial instruments is detailed in note 12 to the consolidated financial statements. The arrangements and policies concerning the Company's financial instruments are under constant review and may change depending upon the prevailing market conditions.

The Company's capital structure mix is also monitored on a continual basis to ensure that it optimizes flexibility, minimizes cost and offers the greatest opportunity for growth. This includes the determination of a reasonable level of debt and any interest rate exposure risk that may exist.

The Company continues to employ an Environmental Management Plan (the "Plan") to ensure the welfare of its employees, the communities in which it operates, and the environment as a whole. Environmental protection is of fundamental importance and is undertaken in accordance with guiding principles approved by the Company's Board of Directors. A detailed copy of the Company's Plan is presented to, and reviewed by, the Board of Directors annually. The Plan is updated quarterly at the Directors' meetings.

Environment

The Company's environmental management plan and operating guidelines focus on minimizing the impact of field operations while meeting regulatory requirements and corporate standards. The Company, as part of this plan, has implemented a proactive program that includes:

- An annual internal environmental compliance audit and inspection program of the Company's operating facilities;
- An aggressive suspended well inspection program to support future development or eventual abandonment;
- Appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment;
- An effective surface reclamation program;
- A progressive due diligence program related to groundwater monitoring;
- A rigorous program related to preventing and reclaiming spill sites;
- A solution gas reduction and conservation program; and
- A program to replace the majority of fresh water for steaming with brackish water.

The Company has also established stringent operating standards in four areas:

- Using water-based, environmentally friendly drilling muds whenever possible;
- Implementing cost effective ways of reducing greenhouse natural gas emissions per unit of production;

- Exercising care with respect to all waste produced through effective waste management plans; and
- Minimizing produced water volumes onshore and offshore through cost-effective measures.

In 2004, the Company's capital expenditures included $32 million for abandonment expenditures, down from $40 million in 2003 (2002 – $43 million).

Estimated future site restoration liability

($ millions)	2004	2003
North America	$ 1,776	$ 1,491
North Sea	1,263	764
Offshore West Africa	24	26
	3,063	2,281
North Sea PRT recovery	(601)	(331)
	$ 2,462	$ 1,950

The estimate of the future site restoration liability is based on estimates of future costs to abandon and restore the wells, production facilities and offshore production platforms. There are numerous factors that affect these costs including such things as the number of wells drilled, well depth and the specific environmental legislation. The estimated costs are based on engineering estimates using current costs and technology in accordance with present legislation and industry practice. It is important to note that the future abandonment costs to be incurred by the Company in the North Sea will result in an estimated recovery of PRT of $601 million (2003 – $331 million, 2002 – $305 million), as abandonment costs are an allowable deduction in determining PRT and may be carried back to reclaim PRT previously paid. The PRT recovery reduces the net abandonment liability of the Company to $2,462 million (2003 – $1,950 million, 2002 – $1,681 million). The Company's strategy in the North Sea consists of developing commercial hubs around its core operated properties with the goal of increasing production, lowering costs and extending the economic lives of its production facilities, thereby delaying the eventual abandonment dates.

Kyoto Protocol

In December 2002, the Canadian Federal Government ratified the Kyoto Protocol ("Kyoto"). The Company continues to work with departments of the Federal and Provincial governments as legislation and regulatory mechanisms to address the issue of climate change develop. The Federal Government has addressed the uncertainty around the ratification and implementation of Kyoto by providing the oil and gas sector with limits on the cost for large industrial emitters until 2012. For long-term, capital intensive investments, such as the Horizon Project, it is essential for the Company to understand the cost implications associated with the climate change policies beyond 2012. To address these concerns, the Federal Government outlined eight principles that would guide them in its negotiations and policies for the post 2012 years. On the basis of these principles, the Company continued to work on the development plan of the Horizon Project. Accordingly, the Company will continue to develop strategies that will enable it to deal with the risks and opportunities associated with new climate change policies. In addition, the Company will work with relevant parties to ensure that new policies encourage innovation, energy efficiency, targeted research and development while not impacting Canada's competitive position.

Critical accounting estimates

The preparation of financial statements requires Management to make judgements, assumptions and estimates in the application of generally accepted accounting principles that have a significant impact on the financial results of the Company. Actual results could differ from those estimates. A comprehensive discussion of the Company's significant accounting policies is contained in note 1 to the consolidated financial statements. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

Full cost accounting

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the CICA. Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. The capitalized costs and future capital costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. The carrying amount of oil and natural gas properties in each cost centre may not exceed their recoverable amount ("the ceiling test"). The recoverable amount is calculated as the undiscounted cash flow using proved reserves and estimated future prices and costs. If the carrying amount of a cost centre exceeds its recoverable amount, then an impairment loss equal to the amount by which the carrying amount of the properties exceeds their fair value is charged against net earnings. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

The alternate acceptable method of accounting for oil and natural gas properties and equipment is the successful efforts method. A major difference in applying the successful efforts method is that exploratory dry holes and geological and geophysical exploration costs would be charged against net earnings in the year incurred rather than being capitalized to property, plant and equipment. In addition, under this method cost centres are defined based on reserve pools rather than by country.

Oil and natural gas reserves

The Company retains qualified independent reserves evaluators to evaluate the Company's proved and probable oil and natural gas reserves. In 2004, 100% of the Company's reserves were evaluated by qualified independent reserves evaluators.

The estimation of reserves involves the exercise of judgement. Forecasts are based on engineering data, future prices, expected future rates of production and the timing of future capital expenditures, all of which are subject to many uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion, depreciation and amortization. A revision to the reserve estimate could result in a higher or lower DD&A charge to net earnings. Downward revisions to reserve estimates could also result in a write-down of oil and natural gas property, plant and equipment carrying amounts under the ceiling test.

Asset retirement obligation

The fair value of asset retirement obligations related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of associated capital assets and are are amortized to expense through depletion over the life of the asset. The fair value of the asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. Differences between actual and estimated costs to settle the asset retirement obligation, timing of cash flows to settle the obligation and future inflation rates could result in gains or losses on the settlement of the asset retirement obligations.

Risk management activities

Financial instruments that do not qualify as hedges under Accounting Guideline 13 or are not designated as hedges are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principle amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on interest rate contracts not designated as hedges are included in risk management activities.

The Company enters into cross currency swap agreements to manage its currency exposure on long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Purchase price allocations

The costs of corporate and asset acquisitions are allocated to the acquired assets and liabilities based on their fair value at the time of acquisition. The determination of fair value requires Management to make assumptions and estimates regarding future events. The allocation process is inherently subjective and impacts the amount assigned to individually identifiable assets and liabilities. As a result, the purchase price allocation impacts the Company's reported assets and liabilities and future net earnings due to the impact on future DD&A expense and impairment tests.

Production sharing contractual arrangements

The Company's operations outside of North America and the North Sea are governed by production sharing contracts ("PSC"). Under the PSC, the Company and its working interest partners typically bear all the risks and costs for exploration, development and production. In exchange, if exploration is successful, the Company is given the opportunity to recover its investment and production expenses from the sale of crude oil and natural gas production ("cost oil"). The Company is also entitled to a share of the excess of what is required to recover the Company's investment and production expenses ("profit oil"), the allocation of which varies from contract to contract. Together the cost oil and profit oil represent the Company's entitlement. The Company records production, sales and reserves based on its working interest ownership. The PSC stipulates that income taxes are to be paid out of the respective national oil company share of production. The difference between the Company's working interest ownership and its annual entitlement is accounted for either a royalty expense or current income tax expense in accordance with the PSC.

New accounting standards

Full cost accounting

Effective January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 16 "Oil and Gas Accounting – Full Cost". The Guideline modifies the ceiling test, which limits the aggregate capitalized costs that may be carried forward to future periods. Specific new guidance was provided on several issues, including the frequency of conducting cost centre impairment tests, the testing for cost centre recoverability and the method of determining fair value. The Guideline recommends that cost centre impairment tests should be conducted at each annual balance sheet date. Recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to their recoverable amount calculated as the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment should be recognized on the amount by which the carrying amount of the assets exceeds the fair value of the assets, calculated as the present value of expected cash flows using proved and probable reserves and expected future prices and costs. The adoption of this standard had no effect on the Company's consolidated financial statements for the year ended December 31, 2004.

Asset retirement obligations

Effective January 1, 2004, the Company retroactively adopted the CICA's Section 3110, "Asset Retirement Obligations". The Section requires the recognition of a liability for the fair value of the asset retirement obligation related to long-term assets. Retirement costs equal to the fair value of the asset retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows. This new standard was adopted retroactively and prior period comparative balances have been restated. Adoption of the standard had the following effects on the Company's consolidated balance sheet as at December 31, 2003:

($ millions)		December 31, 2003
Consolidated balance sheet		
Increase property, plant and equipment	$	445
Decrease future site restoration liability	$	(447)
Increase asset retirement obligation	$	897
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

Adoption of the standard had the following effects on the Company's consolidated statements of earnings and retained earnings:

		Year Ended				
($ millions)		**2004**		2003		2002
Increase opening retained earnings	**$**	**6**	$	10	$	41
Decrease depletion, depreciation and amortization	**$**	**(120)**	$	(56)	$	(16)
Increase asset retirement obligation accretion	**$**	**51**	$	62	$	68
Increase (decrease) future income tax expense	**$**	**28**	$	(2)	$	(21)

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

Risk management activities

On January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Guideline 13 and EIC 128 require that financial instruments that are not designated as hedges be recorded on the Company's consolidated balance sheet at fair value on the date thereof, with subsequent changes in fair value recorded in earnings on a quarterly reporting basis. Adoption of Guideline 13 and EIC 128 resulted in the Company recognizing an unrealized mark-to-market gain of $40 million ($27 million, net of tax) for the year ended December 31, 2004 relating to its financial instruments. The unrealized gain assumes that all unsettled derivative financial instruments were settled on December 31, 2004 and were valued based on market conditions existing at that point in time. As a result of the adoption of this standard, the Company expects the volatility in its net earnings to increase, which is directly attributable to the corresponding volatility in crude oil and natural gas prices and the unsettled derivative financial instruments. The Guideline had the following effects on the Company's consolidated financial statements:

($ millions)		**January 1, 2004**
Consolidated balance sheet		
Increase derivative financial instruments asset	**$**	**40**
Increase deferred revenue	**$**	**40**

Preferred Securities

Effective December 31, 2004, the Company early adopted changes to the CICA's Section 3860, "Financial Instruments – Presentation and Disclosure" that relate to contractual obligations that may be settled by delivery of the Company's common shares. Under the new rules, these obligations must be classified as liabilities on the Company's consolidated balance sheets. Previously, these obligations were classified as equity. These changes have been adopted retroactively and prior periods have been restated. Adoption of the changes had the following effects on the Company's consolidated financial statements:

($ millions)		**2004**		2003		2002
Increase long-term debt	**$**	**96**	$	103	$	126
Decrease preferred securities	**$**	**(96)**	$	(103)	$	(126)
Increase interest expense	**$**	**9**	$	9	$	10
Increase foreign exchange gain	**$**	**7**	$	23	$	1
(Decrease) increase future income tax expense	**$**	**(1)**	$	1	$	(4)
Decrease dividend on preferred securities, net of tax	**$**	**(5)**	$	(5)	$	(6)
Decrease revaluation of preferred securities, net of tax	**$**	**(4)**	$	(18)	$	(1)

Impairment of long-lived assets

Effective January 1, 2004, the Company prospectively adopted the CICA's Section 3063 "Impairment of Long-lived Assets". The Section establishes standards for the recognition, measurement and disclosure of the impairment of long-lived assets. The Section addresses when impairment should be recognized and how to measure the amount of impairment. An impairment loss is recognized when the carrying amount of a long-lived asset exceeds its fair value calculated as the sum of the undiscounted cash flows expected to result from its use and eventual disposition. An impairment loss is measured as the amount by which the long-lived assets' carrying amount exceeds its fair value. Adoption of the Section had no effect on the Company's consolidated financial statements for the year ended December 31, 2004.

Variable interest entities ("VIE's")

Effective January 1, 2004, the Company retroactively adopted the CICA's Accounting Guideline 15, "Consolidation of Variable Interest Entities" without restating prior periods. The Guideline requires the Company to identify VIE's in which they have an interest, determine whether they are the primary beneficiary of such entities and, if so, consolidate them. The primary beneficiary is the enterprise that will absorb or receive the majority of the VIE's expected losses, expected residual returns, or both. A VIE is an entity where (1) its equity investment at risk is insufficient to permit the entity to finance its activities without additional subordinated support from others, (2) the equity investors lack either voting control, an obligation to absorb expected losses or the right to receive expected residual returns, and (3) it does not meet specified exemption criteria. The adoption of this Guideline had no impact on the Company's consolidated financial statements.

Financial instruments

In January 2005, the CICA issued Section 3855 "Financial Instruments – Recognition and Measurement". This Section prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet and at what amount – sometimes using fair value; other times using cost-based measures. This Section also specifies how financial instruments gains and losses are to be presented. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Transitional provisions for this Section are complex and vary based on the type of financial instruments under consideration. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Hedges

In January 2005, the CICA issued Section 3865 "Hedges". This Section expands on existing Accounting Guideline 13, "Hedging Relationships", and Section 1650 "Foreign Currency Translation", by specifying how hedge accounting is applied and what disclosures are necessary when it is applied. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Retroactive application of this Section is not permitted. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Comprehensive Income

In January 2005, the CICA issued Section 1530 "Comprehensive Income". This Section introduces new standards for reporting and display of comprehensive income. Comprehensive income is the change in equity (net assets) of a company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Financial statements of prior periods are required to be restated for certain comprehensive income items. In addition, a company is encouraged, but not required to present reclassification adjustments, in comparative financial statements provided for earlier periods. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Equity

In January 2005, the CICA issued Section 3251 "Equity". This Section replaces Section 3250 "Surplus". It establishes standards for the presentation of equity and changes in equity during a reporting period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Financial statements of prior periods are required to be restated for certain specified adjustments. For all other items, comparative financial statements are presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required. In addition, a company is encouraged, but not required to present reclassification adjustments, in comparative financial statements provided for earlier periods. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Outlook

The Company continues its strategy of maintaining a large portfolio of varied projects, which enables the Company over an extended period of time to provide consistent growth in production and high shareholder returns. Annual budgets are developed, scrutinized throughout the year and changed if necessary in the context of project returns, product pricing expectations, and balance in project risk and time horizons. The Company maintains a high ownership level and operatorship level in all of its properties and can therefore control the nature, timing and extent of capital expenditures in each of its project areas.

The Company expects production levels in 2005 to average 1,448 to 1,510 mmcf/d of natural gas and 307,000 to 335,000 bbl/d of crude oil and NGLs. First quarter 2005 production guidance for natural gas is 1,400 to 1,482 mmcf/d of natural gas and 269,000 to 290,000 bbl/d of crude oil and NGLs.

The budgeted capital expenditures in 2005 are currently expected to be as follows:

($ millions)	2005 Budget
North America natural gas	$ 1,350
North America crude oil and NGLs	910
North Sea crude oil and NGLs	420
Offshore West Africa crude oil and NGLs	400
Property acquisitions and midstream	50
	3,130
Horizon Oil Sands Project	1,372
Total	$ 4,502

North America natural gas

In 2005, the Company expects to drill approximately 1,033 net natural gas wells, 690 net crude oil wells and 199 stratigraphic test/service wells. The 2005 North American natural gas program will be highlighted by expanded drilling programs in the Northwest Alberta and Northeast British Columbia core regions as shown below:

(number of wells)	2005 Budget
Northeast British Columbia	240
Northwest Alberta	194
Northern Plains	205
Southern Plains	394
Total	1,033

Drilling in 2005 reflects higher activity levels targeting the shallow Notikewin zone in Northeast British Columbia as well as increased Cardium drilling in Northwest Alberta. Drilling of shallow gas and coal bed methane wells will increase in the Southern Plains core region. Conventional drilling will also increase in the Northern Plains core region. During 2005, approximately 90 wells targeting deep natural gas are budgeted, including nine in the Foothills area. The Foothills area drilling increases reflect both increased focus on the area as well as new drilling targets identified on assets acquired during the first half of 2004.

North America crude oil and NGLs

The 2005 drilling program consists of:

(number of wells)	2005 Budget
Conventional heavy crude oil	398
Thermal heavy crude oil	105
Light crude oil	101
Pelican Lake crude oil	67
Total	671

The 2005 drilling program consists of 398 conventional heavy crude oil wells, 105 thermal heavy crude oil wells, 101 light crude oil wells and 67 Pelican Lake crude oil wells. The Company continues the disciplined development of its heavy crude oil resources. Conventional heavy crude oil drilling will increase, reflecting favourable crude oil prices as well as new opportunities identified in the property acquisitions made during 2004. Due to the nature of heavy crude oil production patterns, where production volumes ramp up during the first months of production, much of the production resulting from the expanded drill program will not be realized until late 2005.

In 2005, the Company expects to continue its Primrose thermal crude oil expansion plans. The two new phases that commenced production in mid 2004 significantly enhance the economics of this project and are a positive indicator for future pads that will be drilled. Production from this project is subject to the cycling of steam injection and crude oil production and is expected to remain at similar levels to the 2004 production.

The Pelican Lake waterflood test program continues and will be expanded to additional lands in the area. The Company will also be piloting the use of polymer flood on a portion of the field in an effort to further enhance field recoveries.

As a result of the above activities, North America 2005 crude oil and NGLs production is expected to increase slightly from 2004 levels.

Based upon the capital expenditure budget, the Company expects to incur Canadian current income tax expense in 2005 of $200 to $300 million.

The Horizon Oil Sands Project

The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is planned to begin at 110,000 bbl/d of 34° API light, sweet synthetic crude oil ("SCO"). Phase 2 will increase production to155,000 bbl/d of SCO. Phase 3 will further increase production to 232,000 bbl/d of SCO. The phased approach provides the Company with improved cost and project controls including labour and materials management, and directionally mitigates the effects of growth on local infrastructure.

Total expected capital costs for all three phases of the development are estimated at $10.8 billion. Capital costs for Phase 1 of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008, respectively.

Extensive front end design and the high degree of project definition have enabled the Company to obtain approximately 68% of Phase 1 costs on a fixed price basis. The high degree of up front project engineering and pre-planning will also reduce the risks associated with scope changes.

On February, 9, 2005, the Board of Directors unanimously authorized management to proceed with Phase 1 of the Horizon Project.

North Sea

The capital budget in 2005 for the North Sea is $420 million and includes the drilling of approximately 12 net platform wells while continuing the successful workover and recompletion program. The Company will also conduct a mobile drilling program in which four subsea wells will be drilled at Nadia, Thelma (two) and Columba E. These wells, with the exception of Nadia, are step-out development wells on existing proved properties. The Nadia well is an exploration of new terraces in the Ninian/Columba area. Average crude oil production is expected to increase from 2004 production levels; however, natural gas volumes will be lower as natural gas sales at the Banff Field are diverted to reinjection.

Offshore West Africa

In 2005, the capital budget for Offshore West Africa is set at $400 million, of which the Company anticipates $210 million to be spent on finalizing the development of the Baobab Field in Côte d'Ivoire and $100 million to be spent developing the West Espoir Field. The remainder will be spent on various exploration activities.

At East Espoir, an additional four wells are scheduled for drilling in early 2005 as a result of additional testing and evaluation that revealed a larger quantity of crude oil in place, based upon reservoir studies and production history to date. These new producer wells will effectively exploit this additional potential and could increase the recoverable resources from the field.

Average production is expected to increase as a result of the commissioning of the Baobab Field in mid 2005 as well as a result of the drilling of additional producer wells in East Espoir.

Sensitivity analysis

The following table is indicative of the annualized sensitivities of cash flow and net earnings from changes in certain key variables. The analysis is based on business conditions and production volumes during the fourth quarter of 2004. Each separate item in the sensitivity analysis shows the effect of an increase in that variable only; all other variables are held constant.

	Cash flow from operations ($ millions)	Cash flow from operations ($/share, basic)	Net earnings ($ millions)	Net earnings ($/share, basic)
Price changes				
Crude oil – WTI US$1.00/bbl (1)				
Excluding financial derivatives	$ 96	$ 0.36	$ 68	$ 0.25
Including financial derivatives	$ 80	$ 0.30	$ 43	$ 0.16
Natural gas – AECO C$0.10/mcf (1)				
Excluding financial derivatives	$ 37	$ 0.14	$ 24	$ 0.09
Including financial derivatives	$ 33	$ 0.12	$ 21	$ 0.08
Volume changes				
Crude oil – 10,000 bbl/d	$ 73	$ 0.27	$ 34	$ 0.13
Natural gas – 10 mmcf/d	$ 18	$ 0.07	$ 7	$ 0.03
Foreign currency rate change				
$0.01 change in C$ in relation to US$ (1)				
Excluding financial derivatives	$ 56	$ 0.21	$ 12	$ 0.05
Including financial derivatives	$ 55 - 58	$ 0.21 - 0.22	$ 12 - 13	$ 0.04 - 0.05
Interest rate change – 1%	$ 13	$ 0.05	$ 13	$ 0.05

(1) For details of financial instruments in place, see consolidated financial statements note 12.

Daily production by segment, before royalties

	Q1	Q2	Q3	Q4	2004	2003	2002
Crude oil and NGLs (bbl/d)							
North America	192,151	203,741	214,336	214,493	206,225	174,895	169,675
North Sea	57,099	60,105	71,517	69,971	64,706	56,869	38,876
Offshore West Africa	12,036	11,552	11,409	11,240	11,558	10,628	6,784
Total	261,286	275,398	297,262	295,704	282,489	242,392	215,335
Natural gas (mmcf/d)							
North America	1,230	1,389	1,336	1,365	1,330	1,245	1,204
North Sea	54	55	53	40	50	46	27
Offshore West Africa	10	8	7	5	8	8	1
Total	1,294	1,452	1,396	1,410	1,388	1,299	1,232
Barrels of oil equivalent (boe/d)							
North America	397,194	435,238	436,986	442,072	427,936	382,315	370,337
North Sea	66,127	69,175	80,393	76,560	73,093	64,469	43,391
Offshore West Africa	13,623	12,930	12,567	12,113	12,806	12,030	6,994
Total	476,944	517,343	529,946	530,745	513,835	458,814	420,722

Per unit results

	Q1	Q2	Q3	Q4	2004	2003	2002
Crude oil and NGLs ($/bbl)							
Sales price (1)	$ 34.21	$ 36.72	$ 43.50	$ 36.92	$ 37.99	$ 32.66	$ 31.22
Royalties	2.91	3.15	3.59	2.95	3.16	2.77	3.16
Production expense	9.58	9.92	10.21	10.41	10.05	10.28	8.45
Netback	$ 21.72	$ 23.65	$ 29.70	$ 23.56	$ 24.78	$ 19.61	$ 19.61
Natural gas ($/mcf)							
Sales price (1)	$ 6.31	$ 6.64	$ 6.24	$ 6.77	$ 6.50	$ 6.21	$ 3.77
Royalties	1.27	1.38	1.39	1.34	1.35	1.32	0.78
Production expense	0.65	0.66	0.71	0.68	0.67	0.60	0.57
Netback	$ 4.39	$ 4.60	$ 4.14	$ 4.75	$ 4.48	$ 4.29	$ 2.42
Barrels of oil equivalent ($/boe)							
Sales price (1)	$ 35.88	$ 38.20	$ 40.92	$ 38.51	$ 38.45	$ 34.84	$ 27.02
Royalties	5.03	5.55	5.68	5.21	5.37	5.20	3.91
Production expense	7.02	7.12	7.59	7.61	7.35	7.15	5.99
Netback	$ 23.83	$ 25.53	$ 27.65	$ 25.69	$ 25.73	$ 22.49	$ 17.12

(1) Including transportation costs and excluding risk management activities.

Netback analysis

($/boe, except daily production)	2004	2003	2002
Daily production, before royalties (boe/d)	513,835	458,814	420,722
Sales price [1]	$ 38.45	$ 34.84	$ 27.02
Royalties	5.37	5.20	3.91
Production expense	7.35	7.15	5.99
Netback	25.73	22.49	17.12
Midstream contribution	(0.26)	(0.28)	(0.25)
Administration	0.61	0.52	0.40
Share bonus plan	0.05	–	–
Interest	1.01	1.20	1.26
Realized risk management activities loss	2.52	1.09	0.54
Realized foreign exchange loss	0.02	0.05	0.02
Taxes other than income tax – current	1.12	0.69	0.35
Current income tax – North America	0.47	0.14	–
Current income tax – Large Corporations Tax	0.05	0.06	0.14
Current income tax – North Sea	0.01	0.26	(0.13)
Current income tax – Offshore West Africa	0.07	0.09	0.04
Current income tax – other	0.01	–	–
Cash flow	$ 20.05	$ 18.67	$ 14.75

(1) Including transportation costs and excluding risk management activities.

Quarterly financial information

($ millions, except per share amounts)		Q1	Q2	Q3	Q4	Total
2004						
Revenue		$ 1,638	$ 1,865	$ 2,075	$ 1,969	$ 7,547
Net earnings		$ 258	$ 259	$ 311	$ 577	$ 1,405
Per common share	– basic	$ 0.96	$ 0.97	$ 1.16	$ 2.15	$ 5.24
	– diluted	$ 0.96	$ 0.97	$ 1.13	$ 2.13	$ 5.20
Cash flow from operations		$ 848	$ 930	$ 1,041	$ 950	$ 3,769
Per common share	– basic	$ 3.16	$ 3.47	$ 3.88	$ 3.54	$ 14.06
	– diluted	$ 3.14	$ 3.47	$ 3.85	$ 3.52	$ 13.98
2003						
Revenue		$ 1,840	$ 1,502	$ 1,454	$ 1,359	$ 6,155
Net earnings [1]		$ 427	$ 525	$ 201	$ 250	$ 1,403
Per common share	– basic [1][2]	$ 1.60	$ 1.96	$ 0.75	$ 0.93	$ 5.23
	– diluted [1][2]	$ 1.52	$ 1.89	$ 0.74	$ 0.91	$ 5.06
Cash flow from operations		$ 906	$ 762	$ 758	$ 734	$ 3,160
Per common share	– basic [2]	$ 3.38	$ 2.84	$ 2.81	$ 2.74	$ 11.77
	– diluted [2]	$ 3.27	$ 2.79	$ 2.78	$ 2.71	$ 11.53

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) Restated to reflect two-for-one share split in May 2004.

The following discussion highlights some of the more significant factors that impacted the net earnings in the eight most recently completed quarters.

In the first quarter of 2004, the Company acquired certain resource properties, collectively known as Petrovera, in its Northern Plains core region.

In the second quarter of 2004, the Company completed the acquisition of certain resource properties located in Northeast British Columbia and Northwest Alberta. These properties include further ownership in the Ladyfern natural gas field.

In the third quarter of 2004, the Company acquired certain light crude oil producing properties in the Central North Sea. The acquired properties comprise operated interests in T-Block (Tiffany, Toni and Thelma Fields) and B-Block (Balmoral, Stirling and Glamis Fields).

In the fourth quarter of 2004, the Company completed the acquisition of certain resource properties located in Alberta, British Columbia and Saskatchewan. The acquisition extends the Company's Northern Plains core region into the light crude oil operating area of Dawson. The Company issued US$350 million of debt securities maturing 2014, bearing interest at 4.90% and US$350 million of debt securities maturing 2035, bearing interest at 5.85%.

In the second quarter of 2003, the Canadian Government introduced several income tax changes, including rate reductions, for the resource industry. In addition, the Province of Alberta reduced corporate income tax rates. As a result of these changes, the future income tax liability was decreased by $247 million. Also, in the second quarter of 2003, the Company modified its employee stock option plan to provide for a cash payment option. A charge of $72 million after taxes ($105 million before taxes) was recognized to represent the mark-to-market liability of the plan for all earned options as at June 30, 2003.

Trading and share statistics

	Q1	Q2	Q3	Q4	2004 Total	2003 Total
TSX – C$						
Trading volume (thousands)	69,449	80,934	65,017	87,612	303,012	295,351
Share price ($/share)						
High	$ 38.25	$ 40.85	$ 51.04	$ 55.15	$ 55.15	$ 33.61
Low	$ 31.91	$ 35.08	$ 39.75	$ 45.80	$ 31.91	$ 22.60
Close	$ 36.35	$ 40.05	$ 50.50	$ 51.25	$ 51.25	$ 32.69
Market capitalization at December 31 ($ millions)					$ 13,744	$ 8,742
Shares outstanding (thousands)					268,181	267,463
NYSE – US$						
Trading volume (thousands)	11,775	16,418	13,255	21,286	62,734	23,458
Share price ($/share)						
High	$ 28.94	$ 30.54	$ 40.31	$ 44.74	$ 44.74	$ 25.70
Low	$ 23.88	$ 25.88	$ 29.72	$ 37.12	$ 23.88	$ 14.63
Close	$ 27.82	$ 29.90	$ 39.83	$ 42.77	$ 42.77	$ 25.22
Market capitalization at December 31 ($ millions)					$ 11,470	$ 6,745
Shares outstanding (thousands)					268,181	267,463

Management's Report

The accompanying consolidated financial statements and all information in the annual report are the responsibility of management. The consolidated financial statements have been prepared by management in accordance with the accounting policies in the notes to the consolidated financial statements. Where necessary, management has made informed judgements and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared in accordance with Canadian generally accepted accounting principles appropriate in the circumstances. The financial information elsewhere in the annual report has been reviewed to ensure consistency with that in the consolidated financial statements.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are appropriately authorized, assets are safeguarded from loss or unauthorized use and financial records are properly maintained to provide reliable information for preparation of financial statements.

PricewaterhouseCoopers LLP, an independent firm of Chartered Accountants, has been engaged, as approved by a vote of the shareholders at the Company's most recent Annual General Meeting, to examine the consolidated financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion. Their report is presented with the consolidated financial statements.

The Board of Directors (the "Board") is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal controls. The Board exercises this responsibility through the Audit Committee of the Board. This committee, which is comprised of non-management directors, meets with management and the external auditors to satisfy itself that management responsibilities are properly discharged and to review the consolidated financial statements before they are presented to the Board for approval. The consolidated financial statements have been approved by the Board on the recommendation of the Audit Committee.

John G. Langille CA
President & Director
February 18, 2005

Douglas A. Proll CA
Senior Vice President, Finance

Randall Davis

Randall S. Davis CA
Vice President, Financial
Accounting & Controls

Auditors' Report

To the Shareholders of Canadian Natural Resources Limited,

We have audited the consolidated balance sheets of Canadian Natural Resources Limited as at December 31, 2004 and 2003 and the consolidated statements of earnings, retained earnings and cash flows for each of the years in the three year period ended December 31, 2004. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada
February 18, 2005

Comments by Auditor for U.S. readers on Canada-U.S. Reporting Differences

In the United States, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) when there is a change in accounting principles that has a material effect on the comparability of the Company's consolidated financial statements, such as the change described in Note 2 to the consolidated financial statements. Our report to the shareholders dated February 18, 2005 is expressed in accordance with Canadian reporting standards which do not require a reference to such a change in accounting principles in the Auditors' report when the change is properly accounted for and adequately disclosed in the consolidated financial statements.

PricewaterhouseCoopers LLP
Chartered Accountants

Calgary, Alberta, Canada
February 18, 2005

Consolidated Balance Sheets

As at December 31

(millions of Canadian dollars)	2004	2003
ASSETS		
Current assets		
Cash	$ 28	$ 104
Accounts receivable and other	1,176	751
Current portion of other long-term assets (note 4)	34	–
	1,238	855
Property, plant and equipment (note 5)	17,064	13,714
Other long-term assets (note 4)	108	74
	$ 18,410	$ 14,643
LIABILITIES		
Current liabilities		
Accounts payable	$ 379	$ 464
Accrued liabilities	1,057	582
Current portion of long-term debt (note 6)	194	184
Current portion of other long-term liabilities (note 7)	260	130
	1,890	1,360
Long-term debt (note 6)	3,538	2,748
Other long-term liabilities (note 7)	1,208	938
Future income tax (note 8)	4,450	3,591
	11,086	8,637
SHAREHOLDERS' EQUITY		
Share capital (note 9)	2,408	2,353
Retained earnings	4,922	3,650
Foreign currency translation adjustment (note 10)	(6)	3
	7,324	6,006
	$ 18,410	$ 14,643

Commitments (note 13)

Approved by the Board:

Catherine M. Best
Chair of the Audit Committee
and Director

N. Murray Edwards
Vice-Chairman of the Board
and Director

Consolidated Statements of Earnings

For the years ended December 31
(millions of Canadian dollars, except per common share amounts)

	2004	2003	2002
Revenue	**$ 7,547**	$ 6,155	$ 4,459
Less: royalties	**(1,011)**	(872)	(600)
Revenue, net of royalties	**6,536**	5,283	3,859
Expenses			
Production	**1,400**	1,209	931
Transportation	**250**	262	262
Depletion, depreciation and amortization	**1,769**	1,509	1,298
Asset retirement obligation accretion (note 7)	**51**	62	68
Administration	**115**	87	61
Stock-based compensation (note 7)	**259**	200	–
Interest	**189**	201	203
Risk management activities	**434**	148	83
Foreign exchange gain	**(91)**	(335)	(32)
	4,376	3,343	2,874
Earnings before taxes	**2,160**	1,940	985
Taxes other than income tax (note 8)	**165**	107	63
Current income tax (note 8)	**116**	92	8
Future income tax (note 8)	**474**	338	375
Net earnings	**$ 1,405**	$ 1,403	$ 539
Net earnings per common share (note 11)			
Basic	**$ 5.24**	$ 5.23	$ 2.11
Diluted	**$ 5.20**	$ 5.06	$ 2.04

Consolidated Statements of Retained Earnings

For the years ended December 31
(millions of Canadian dollars)

	2004	2003	2002
Balance – beginning of year as previously reported	**$ 3,644**	$ 2,414	$ 1,908
Change in accounting policy (note 2)	**6**	10	41
Balance – beginning of year as restated	**3,650**	2,424	1,949
Net earnings	**1,405**	1,403	539
Dividend on common shares (note 9)	**(107)**	(81)	(64)
Purchase of common shares (note 9)	**(26)**	(96)	–
Balance – end of year	**$ 4,922**	$ 3,650	$ 2,424

Consolidated Statements of Cash Flows

For the years ended December 31

(millions of Canadian dollars)	2004	2003	2002
Operating activities			
Net earnings	**$ 1,405**	$ 1,403	$ 539
Non-cash items			
Depletion, depreciation and amortization	**1,769**	1,509	1,298
Asset retirement obligation accretion	**51**	62	68
Stock-based compensation	**249**	200	–
Unrealized risk management activities	**(40)**	–	–
Unrealized foreign exchange gain	**(94)**	(343)	(36)
Deferred petroleum revenue tax (recovery)	**(45)**	(9)	10
Future income tax	**474**	338	375
Deferred charges	**(33)**	10	(84)
Abandonment expenditures	**(32)**	(40)	(43)
Net change in non-cash working capital (note 14)	**(14)**	(48)	(157)
	3,690	3,082	1,970
Financing activities			
Issue (repayment) of bank credit facilities	**357**	(647)	(1,234)
Repayment of medium-term notes	**(125)**	–	–
Repayment of senior unsecured notes	**(54)**	(85)	(16)
Issue of US dollar debt securities	**830**	–	1,749
Repayment of obligations under capital leases	**(7)**	(8)	(4)
Dividend on common shares	**(101)**	(77)	(60)
Issue of common shares on exercise of stock options	**24**	89	84
Purchase of common shares	**(33)**	(144)	–
Net change in non-cash working capital (note 14)	**6**	(11)	27
	897	(883)	546
Investing activities			
Expenditures on property, plant and equipment	**(4,582)**	(2,486)	(2,552)
Net proceeds on sale of property, plant and equipment	**7**	20	76
Net expenditures on property, plant and equipment	**(4,575)**	(2,466)	(2,476)
Net change in non-cash working capital (note 14)	**(88)**	341	(25)
	(4,663)	(2,125)	(2,501)
(Decrease) increase in cash	**(76)**	74	15
Cash – beginning of year	**104**	30	15
Cash – end of year	**$ 28**	$ 104	$ 30

Supplemental disclosure of cash flow information (note 14)

Notes to the Consolidated Financial Statements

(tabular amounts in millions of Canadian dollars, unless otherwise stated)

1. Accounting policies

Canadian Natural Resources Limited (the "Company") is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta, Canada. The Company's operations are focused in North America, largely in western Canada, the North Sea and Offshore West Africa.

Within western Canada, the Company is developing its Horizon Oil Sands Project (the "Horizon Project") and maintains its midstream activities. The Horizon Project involves a plan to recover bitumen through mining operations, while the midstream activities include the Company's pipeline operations and an electricity co-generation system.

The consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in Canada.

A summary of differences between accounting principles in Canada and those generally accepted in the United States ("US") is contained in note 17.

Significant accounting policies are summarized as follows:

Principles of consolidation

The consolidated financial statements include the accounts of the Company and all of its subsidiaries and partnerships. A significant portion of the Company's activities are conducted jointly with others and the consolidated financial statements reflect only the Company's proportionate interest in such activities.

Measurement uncertainty

Management has made estimates and assumptions regarding certain assets, liabilities, revenues and expenses in the preparation of the consolidated financial statements. Such estimates primarily relate to unsettled transactions and events as of the date of the consolidated financial statements. Accordingly, actual results may differ from estimated amounts.

Depletion, depreciation and amortization, and amounts used for ceiling test calculations are based on estimates of oil and natural gas reserves and commodity prices, production expenses and capital costs required to develop and produce those reserves.. The majority of the Company's reserve estimates are evaluated annually by independent engineering firms. By their nature, estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact of differences between actual and estimated amounts on the consolidated financial statements of future periods could be material.

The calculation of asset retirement obligations includes estimates of the future costs to settle the asset retirement obligation, the timing of the cash flows to settle the obligation, and the future inflation rates. The impact of differences between actual and estimated costs, timing and inflation on the consolidated financial statements of future periods could be material.

The measurement of petroleum revenue tax expense and the related provision in the consolidated financial statements are subject to uncertainty associated with future recoverability of oil and natural gas reserves, commodity prices and the timing of future events, which could result in material changes to deferred amounts.

Cash

Cash comprises cash on hand and demand deposits. Other investments (term deposits and certificates of deposit) with a term to maturity of three months or less from the transaction date are reported as cash equivalents.

Property, plant and equipment

The Company follows the full cost method of accounting for oil and natural gas properties and equipment as prescribed by the Canadian Institute of Chartered Accountants ("CICA"). Accordingly, all costs relating to the exploration for and development of oil and natural gas reserves are capitalized and accumulated in country-by-country cost centres. Administrative overhead incurred during the development phase of large capital projects is capitalized until commercial production commences. Proceeds on disposal of properties are ordinarily deducted from such costs without recognition of profit or loss except where such disposal constitutes a significant portion of the Company's reserves in that country.

For mining activities the property acquisition, exploration and development costs are capitalized.

Depletion, depreciation and amortization

The costs related to each cost centre from which there is production are depleted on the unit-of-production method based on the estimated proved reserves of that country. Volumes of net production and net reserves before royalties are converted to equivalent units on the basis of estimated relative energy content. In determining its depletion base, the Company includes estimated future costs to be incurred in developing proved reserves and excludes the cost of unproved properties and major development projects. The unproved properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the value of the unproved property is considered to be impaired, the cost of the unproved property or the amount of the impairment is added to costs subject to depletion. Certain costs for major development projects from which there has been no commercial production are not subject to depletion until commercial production commences.

Processing and production facilities are depreciated on a straight-line basis over their estimated lives.

The Company reviews the carrying amount of its oil and natural gas properties ("the properties") relative to their recoverable amount ("the ceiling test") for each cost centre at each annual balance sheet date, or earlier if circumstances or events indicate impairment may have occurred. The recoverable amount is calculated as the undiscounted cash flow from the properties using proved reserves and expected future prices and costs. If the carrying amount of the properties exceeds their recoverable amount, then an impairment loss equal to the amount by which the carrying amount of the properties exceeds their fair value is recognized in depletion. Fair value is calculated as the cash flow from those properties using proved and probable reserves and expected future prices and costs, discounted at a risk-free interest rate.

Midstream assets are depreciated on a straight-line basis over their estimated lives. The Company reviews the recoverability of the carrying amount of the midstream assets at each annual balance sheet date. If the carrying amount of the midstream assets exceeds their recoverable amount, then an impairment loss equal to the amount by which the carrying amount of the midstream assets exceeds their fair value is recognized in depreciation.

Head office capital assets are amortized on a declining balance basis over their estimated useful lives.

Deferred charges

Deferred charges include deferred financing costs associated with the issuance of long-term debt and settlement costs of long-term natural gas contracts. Deferred charges are amortized over the original term of the related instrument.

Asset retirement obligation

The fair values of asset retirement obligations related to long-term assets are recognized as a liability in the period in which they are incurred. Retirement costs equal to the fair value of the asset retirement obligations are capitalized as part of the cost of the associated capital assets and are amortized to expense through depletion over the life of the asset. The fair value of the asset retirement obligation is estimated by discounting the expected future cash flows to settle the asset retirement obligation at the Company's credit-adjusted risk-free interest rate. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and for any changes in the amount or timing of the underlying future cash flows.

Foreign currency translation

Foreign operations that are self-sustaining are translated using the current rate method. Under this method, assets and liabilities are translated to Canadian dollars from their functional currency using the exchange rate in effect at the consolidated balance sheet date. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Gains or losses on translation are included in the foreign currency translation adjustment in shareholders' equity in the consolidated balance sheets.

Foreign operations that are integrated are translated using the temporal method. For foreign currency balances and integrated subsidiaries, monetary assets and liabilities are translated to Canadian dollars at the exchange rate in effect at the consolidated balance sheet date and non-monetary assets and liabilities are translated at the exchange rate in effect when the assets were acquired or obligations incurred. Revenues and expenses are translated to Canadian dollars at the monthly average exchange rates. Provisions for depletion, depreciation and amortization are translated at the same rate as the related items.

Gains or losses on the translation of long-term debt denominated in US dollars are either recognized in net earnings immediately, or in the foreign currency translation adjustment (note 10) for translation gains or losses on that portion of the US dollar denominated debt designated as a hedge of self-sustaining foreign operations

Petroleum revenue tax

The Company accounts for future United Kingdom petroleum revenue tax ("PRT") by the life-of-the-field method. The total future liability or recovery of PRT is estimated using current sales prices and costs. The estimated future PRT is apportioned to accounting periods on the basis of total estimated future revenues. Changes in the estimated total future PRT are accounted for prospectively.

Production sharing contract

Production generated from offshore Côte d'Ivoire is shared by the terms of the Production Sharing Contract ("PSC") with the State Oil Company of Côte d'Ivoire ("Petroci"). Revenues are divided into cost recovery revenues and profit revenues. Cost recovery revenues allow the Company to recover the capital and operating costs carried by the Company on behalf of Petroci. These revenues are reported as sales revenues. Profit revenues are allocated to joint venture partners in accordance with their respective equity interests, after a portion has been allocated to the Côte d'Ivoire Government. The Government's share of revenues attributable to the Company's equity interest is reported as either a royalty expense or a current tax expense in accordance with the PSC.

Income tax

The Company follows the liability method of accounting for income taxes. Under this method, future income tax assets and liabilities are recognized based on the estimated tax effects of temporary differences in the carrying value of assets and liabilities in the consolidated financial statements and their respective tax bases, using income tax rates substantively enacted on the consolidated balance sheet date. The effect of a change in income tax rates on the future income tax assets and liabilities is recognized in net earnings in the period of the change.

Revenue recognition
Revenues are recognized when products have been delivered or services have been performed.

Stock-based compensation plans
The Company accounts for its stock-based compensation plans using the fair value method. A liability for expected cash settlements under the Company's Stock Option Plan (the "Option Plan") is accrued over the vesting period of the stock options based on the difference between the exercise price of the stock options and the market price of the Company's common shares. The liability is revalued quarterly to reflect changes in the market price of the Company's common shares and the net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares under the Option Plan, consideration paid by employees, officers or directors and the previously recognized liability associated with the stock options are recorded as share capital.

The Company also has an employee stock savings plan. Contributions to the employee stock savings plan are recorded as compensation expense at the time of the contribution.

The Company also has a stock bonus plan. Contributions to the stock bonus plan are recorded as compensation expense over the vesting period.

Risk management activities
Financial instruments that do not qualify as hedges under Accounting Guideline 13 or are not designated as hedges are recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recognized in net earnings.

The Company utilizes various financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are not used for trading purposes.

The Company enters into commodity price contracts to manage anticipated sales of crude oil and natural gas production in order to protect cash flow for capital expenditure programs. The Company also enters into foreign currency denominated financial instruments to manage future US dollar denominated crude oil and natural gas sales. Gains or losses on these contracts are included in risk management activities.

The Company enters into interest rate swap agreements to manage its fixed to floating interest rate mix on long-term debt. The interest rate swap contracts require the periodic exchange of payments without the exchange of the notional principle amount on which the payments are based. Gains or losses on interest rate swap contracts designated as hedges are included in interest expense. Gains or losses on interest rate contracts not designated as hedges are included in risk management activities.

The Company enters into cross currency swap agreements to manage its currency exposure on long-term debt. The cross currency swap contracts require the periodic exchange of payments with the exchange at maturity of notional principal amounts on which the payments are based. Gains or losses on cross currency swap contracts designated as hedges are included in interest expense.

Gains or losses on the termination of financial instruments that have been accounted for as hedges are deferred under non-current assets or liabilities on the consolidated balance sheets and amortized into net earnings in the period in which the underlying hedged transaction is recognized. In the event a designated hedged item is sold, extinguished or matures prior to the termination of the related derivative instrument, any unrealized gain or loss is recognized in net earnings.

Per common share amounts
The Company uses the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. This method assumes that proceeds received from the exercise of in-the-money stock options not included as a liability are used to purchase common shares at the average market price during the year. The dilutive effect of convertible securities is calculated by applying the "as-if-converted" method, which assumes that the securities are converted at the beginning of the period and that income items are adjusted to net earnings.

Comparative figures
Certain figures provided for prior years have been reclassified to conform to the presentation adopted in 2004.

Common share data has been restated to reflect the two-for-one share split in May 2004.

2. Changes in accounting policies

Asset retirement obligation

Effective January 1, 2004, the Company retroactively adopted the CICA's Section 3110, "Asset Retirement Obligations". The Section requires the recognition of a liability for the fair value of the asset retirement obligation related to long-term assets. Retirement costs equal to the fair value of the asset retirement obligation are capitalized as part of the cost of the associated capital asset and amortized to expense through depletion over the life of the asset. In subsequent periods, the asset retirement obligation is adjusted for the passage of time and any changes in the amount or timing of the underlying future cash flows. Previously, future site restoration costs were accrued over the life of the Company's proved reserves. This new standard was adopted retroactively and prior period comparative balances have been restated. Adoption of the standard had the following effects on the Company's consolidated balance sheet as at December 31, 2003:

	December 31, 2003	
Increase property, plant and equipment	$	445
Decrease future site restoration liability	$	(447)
Increase asset retirement obligation	$	897
Increase future income tax liability	$	3
Decrease foreign currency translation adjustment	$	(14)
Increase retained earnings	$	6

Adoption of the standard had the following effects on the Company's consolidated statements of earnings and retained earnings:

Year Ended December 31		**2004**		2003		2002
Increase opening retained earnings	**$**	**6**	$	10	$	41
Decrease depletion, depreciation and amortization	**$**	**(120)**	$	(56)	$	(16)
Increase asset retirement obligation accretion	**$**	**51**	$	62	$	68
Increase (decrease) future income tax expense	**$**	**28**	$	(2)	$	(21)

Risk management activities

Effective January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-Hedging Derivative Financial Instruments". Guideline 13 addresses the types of items that qualify for hedge accounting, the formal documentation required to enable the use of hedge accounting, and the requirement to evaluate hedges for effectiveness. EIC 128 requires that financial instruments that are not designated as hedges be recorded at fair value on the Company's consolidated balance sheet, with subsequent changes in fair value recorded in earnings. The Company has designated certain of its derivative financial instruments (note 12) as hedges, including certain crude oil collars, natural gas collars, the currency swap on the US$125 million senior unsecured note, and certain interest rate swaps. Adoption of Guideline 13 and EIC 128 had the following effects on the Company's consolidated balance sheet as at January 1, 2004:

	January 1, 2004	
Increase financial instruments asset	**$**	**40**
Increase deferred revenue	**$**	**40**

The deferred revenue will be amortized to earnings over the term of the underlying contracts.

Preferred securities

Effective December 31, 2004, the Company early adopted changes to the CICA's Section 3860 "Financial Instruments – Presentation and Disclosure" that relate to contractual obligations that may be settled by delivery of the Company's common shares. Under the new rules, these obligations must be classified as liabilities on the Company's consolidated balance sheets. Previously, these obligations were classified as equity. These changes have been adopted retroactively and prior periods have been restated. Adoption of the changes had the following effects on the Company's consolidated financial statements:

		2004		2003		2002
Increase long-term debt	**$**	**96**	$	103	$	126
Decrease preferred securities	**$**	**(96)**	$	(103)	$	(126)
Increase interest expense	**$**	**9**	$	9	$	10
Increase foreign exchange gain	**$**	**7**	$	23	$	1
(Decrease) increase future income tax expense	**$**	**(1)**	$	1	$	(4)
Decrease dividend on preferred securities, net of tax	**$**	**(5)**	$	(5)	$	(6)
Decrease revaluation of preferred securities, net of tax	**$**	**(4)**	$	(18)	$	(1)

Full cost accounting

Effective January 1, 2004, the Company prospectively adopted the CICA's Accounting Guideline 16, "Oil and Gas Accounting – Full Cost". The guideline modifies the ceiling test, which limits the aggregate capitalized costs that may be carried forward to future periods. Specific new guidance was provided on several issues, including the frequency of conducting cost centre impairment tests, the testing for cost centre recoverability and the method of determining fair value. The Guideline recommends that cost centre impairment tests should be conducted at each annual balance sheet date. Recovery of costs is tested by comparing the carrying amount of the oil and natural gas assets to their recoverable amount, calculated as the undiscounted cash flows from those assets using proved reserves and expected future prices and costs. If the carrying amount exceeds the recoverable amount, then impairment should be recognized on the amount by which the carrying amount of the assets exceeds the fair value of the assets, calculated as the present value of expected cash flows using proved and probable reserves and expected future prices and costs. The adoption of this standard had no effect on the Company's consolidated financial statements for the year ended December 31, 2004.

3. Business combinations

Petrovera Partnership

In February 2004, the Company acquired certain resource properties in its Northern Plains core region, collectively known as the Petrovera Partnership ("Petrovera"), for $471 million.

The acquisition was accounted for based on the purchase method. Results from Petrovera are consolidated with the results of the Company effective from the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		February 1, 2004
Purchase price:		
Cash consideration	$	467
Cash acquired		(23)
Non-cash working capital deficit assumed		27
Total purchase price	$	471
Purchase price allocated as follows:		
Property, plant and equipment	$	643
Future income tax liability		(129)
Asset retirement obligation		(43)
	$	471

Rio Alto Exploration Ltd.

In July 2002, the Company paid cash of $850 million and issued 20,016,436 common shares with an attributed value of $522 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement (the "Plan of Arrangement"). Rio Alto was engaged in the exploration for and production of oil and natural gas in western Canada and, through wholly owned subsidiaries, in South America. Under the Plan of Arrangement, the subsidiaries of Rio Alto that held its South American properties were sold to a new company, Rio Alto Resources International Inc. ("Rio Alto International"), and each shareholder of Rio Alto received one common share of Rio Alto International for each Rio Alto common share held.

The acquisition was accounted for based on the purchase method. Results from Rio Alto are consolidated with the results of the Company effective from the date of acquisition. The allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		July 1, 2002
Purchase price:		
Cash consideration	$	850
Share consideration		522
Cash acquired		(7)
Non-cash working capital deficit assumed		92
Long-term debt assumed		936
Total purchase price	$	2,393
Purchase price allocated as follows:		
Property, plant and equipment	$	3,412
Future site restoration		(44)
Future income tax		(975)
	$	2,393

4. Other long-term assets

	2004	2003
Risk management (note 12)	$ 66	$ –
Deferred charges	76	74
	142	74
Less: current portion	34	–
	$ 108	$ 74

5. Property, plant and equipment

	2004 Cost	2004 Accumulated depletion and depreciation	2004 Net	2003 Cost	2003 Accumulated depletion and depreciation	2003 Net
Oil and natural gas						
North America	$ 19,750	$ 6,356	$ 13,394	$ 15,914	$ 4,924	$ 10,990
North Sea	2,562	739	1,823	1,971	534	1,437
Offshore West Africa	1,101	192	909	806	139	667
Horizon Project	672	–	672	381	–	381
Midstream	241	32	209	225	25	200
Head office	101	44	57	70	31	39
	$ 24,427	$ 7,363	$ 17,064	$ 19,367	$ 5,653	$ 13,714

During the year ended December 31, 2004, the Company capitalized administrative overhead of $19 million (2003 – $12 million, 2002 – $13 million) relating to exploration and development in the North Sea and Offshore West Africa and $35 million (2003 – $23 million, 2002 – $4 million) relating mainly to the Horizon Project in North America.

Included in property, plant and equipment are unproved land and major development projects that are not subject to depletion or depreciation:

	2004	2003
Oil and natural gas		
North America	$ 1,028	$ 789
North Sea	44	56
Offshore West Africa	536	251
Horizon Project	672	381
	$ 2,280	$ 1,477

6. Long-term debt

	2004	2003
Bank credit facilities		
US dollar bankers' acceptances (2004 – US$471 million, 2003 – US$207 million)	$ 557	$ 268
Medium-term notes		
6.85% unsecured debentures due May 28, 2004	–	125
7.40% unsecured debentures due March 1, 2007	125	125
Senior unsecured notes		
6.42% due May 27, 2004 (2004 – US$nil, 2003 – US$40 million)	–	52
7.69% due December 19, 2005 (2004 – US$125 million, 2003 – US$125 million)	194	194
Adjustable rate due May 27, 2009 (2004 – US$93 million, 2003 – US$93 million)	112	120
Preferred securities		
8.30% due June 25, 2011 (2004 – US$80 million, 2003 – US$80 million)	96	103
US dollar debt securities		
6.70% due July 15, 2011 (2004 – US$400 million, 2003 – US$400 million)	482	517
5.45% due October 1, 2012 (2004 – US$350 million , 2003 – US$350 million)	421	452
4.90% due December 1, 2014 (2004 – US$350 million, 2003 – US$nil)	421	–
7.20% due January 15, 2032 (2004 – US$400 million, 2003 – US$400 million)	482	517
6.45% due June 30, 2033 (2004 – US$350 million, 2003 – US$350 million)	421	452
5.85% due February 1, 2035 (2004 – US$350 million, 2003 – US$nil)	421	–
Obligations under capital leases	–	7
	3,732	2,932
Less: current portion of long-term debt	194	184
	$ 3,538	$ 2,748

Bank credit facilities

The Company has unsecured syndicated bank credit facilities of $3,425 million, comprised of a $100 million operating demand facility, a revolving credit and term loan facility of $1,825 million and a revolving and term loan facility of $1,500 million. The $1,825 million revolving credit and term loan facility is fully revolving for 364-day periods with a term to June 2005 and a provision for extension at the mutual agreement of the Company and the lenders. If not extended, the facility converts to a non-revolving loan with a term of two years. The full amount of the outstanding principal would be repayable at the end of year two following the initiation of the term period. The $1,500 million revolving credit facility has a five-year term, with three, one-year extension provisions. If the facility is not extended, the amount outstanding would be repayable in December 2009. The facilities provide that the borrowings may be made by way of operating advances, prime loans, bankers' acceptances, US base rate loans or US dollar LIBOR advances, which bear interest at the bank's prime rates or at money market rates plus applicable margins.

The Company fixed the exchange rate on the repayment of its US dollar bankers' acceptances using foreign currency financial derivatives (note 12). The US dollar bankers' acceptances were repaid in January 2005 at a C$/US$ exchange rate of 1.180.

The weighted average interest rate of the bank credit facilities outstanding at December 31, 2004, was 3.47% (2003 – 2.32%).

In addition to the outstanding debt, letters of credit aggregating $24 million have been issued.

Medium-term notes

In August 2003, the Company filed a short form shelf prospectus that allows for the issue of up to $1 billion of medium term notes in Canada until September 2005. If issued, these securities will bear interest as determined at the date of issuance. In May 2004, the Company repaid the $125 million 6.85% unsecured debentures due May 2004, which were issued under a previous medium-term note program. The Company has $125 million of unsecured debentures outstanding from a previous medium-term note program.

Senior unsecured notes

The final principal repayment on the 6.95% senior unsecured notes was made in September 2003. The 6.42% senior unsecured notes were repaid in May 2004. In May 2003, the Company prepaid the US$50 million 6.50% senior unsecured notes due May 2008. The adjustable rate senior unsecured notes bear interest at 6.54% and have annual principal repayments of US$31 million commencing in May 2007, through May 2009. These debt instruments contain covenants pertaining to the Company's net worth, certain financial ratios and the ability to grant security. Through a currency swap, the principle and interest repayments on the US$125 million, 7.69% notes due December 2005 have been fixed at $194 million and 7.30%, respectively (note 12).

US dollar debt securities

In December 2004, the Company issued US$350 million of debt securities maturing December 2014, bearing interest at 4.90% and US$350 million of debt securities maturing February 2035, bearing interest at 5.85%. Proceeds from the securities issued were used to repay bankers' acceptances under the Company's bank credit facilities. The Company has entered into certain interest rate swap contracts to convert the fixed rate interest coupon into a floating interest rate on the securities due December 2014 (note 12).

After issuing the above securities, the Company has US$1.3 billion remaining on a US$2.0 billion shelf prospectus filed in May 2003 that allows for the issue of debt securities in the United States until June 2005. If issued, these securities will bear interest as determined at the date of issuance.

Preferred securities

Annual principal repayments of approximately US$27 million are required commencing June 2009 through June 2011. The notes are subordinated to the other long-term debt of the Company and contain, among other things, certain financial covenants restricting the granting of security for new borrowings and the maintenance of specified financial ratios. The Company has the unrestricted right to pay interest, principal and principal prepayment amounts by delivering common shares to the Trustee of the subordinated notes. The semi-annual interest payments may be deferred at the option of the Company for up to two consecutive periods, with a maximum of eight deferral periods over the life of the securities.

Required debt repayments

Required debt repayments are as follows:

Year	Repayment
2005	$ 194
2006	$ –
2007	$ 162
2008	$ 37
2009	$ 69
Thereafter	$ 2,713

No debt repayments are reflected for the bank credit facilities due to the extendable nature of the facilities.

7. Other long-term liabilities

	2004	2003
Asset retirement obligation	$ 1,119	$ 897
Stock-based compensation	323	171
Deferred revenue (note 12)	26	–
	1,468	1,068
Less: current portion	260	130
	$ 1,208	$ 938

Asset retirement obligation

At December 31, 2004, the Company's total estimated undiscounted costs to settle its asset retirement obligations with respect to crude oil and natural gas properties and facilities was $3,063 million (2003 – $2,281 million). These costs will be incurred over several years and have been discounted using a credit-adjusted risk-free interest rate of 6.7%. A reconciliation of the discounted asset retirement obligation is as follows:

	2004	2003
Asset retirement obligation		
Balance – beginning of year	$ 897	$ 867
Liabilities incurred	339	117
Liabilities settled	(32)	(40)
Asset retirement obligation accretion	51	62
Revision of estimates	(86)	(6)
Foreign exchange	(50)	(103)
Balance – end of year	$ 1,119	$ 897

The Company's pipelines and co-generation plant have indeterminant lives and therefore the fair values of the related asset retirement obligations cannot be reasonably determined. The asset retirement obligation for these assets will be recorded in the year in which the lives of the assets are determinable.

Stock-based compensation

The Company's Stock Option Plan ("Option Plan") results in the recognition of a liability for the expected cash settlements under the Option Plan. The current portion represents the amount of the liability that could be realized within the next 12 month period if all vested options are surrendered for cash settlement.

	2004	2003
Stock-based compensation		
Balance – beginning of year	$ 171	$ –
Stock-based compensation provision	259	200
Expense relating to share bonus plan	(10)	–
Cash payment for options surrendered	(80)	(31)
Transferred to common shares	(38)	(8)
Capitalized with respect to Horizon Project	21	10
Balance – end of year	323	171
Less: current portion of stock-based compensation	243	130
	$ 80	$ 41

8. Taxes

Taxes other than income tax

	2004	2003	2002
Current petroleum revenue tax	$ 190	$ 106	$ 41
Deferred petroleum revenue tax	(45)	(9)	10
Provincial capital taxes and surcharges	20	10	11
Other	–	–	1
	$ 165	$ 107	$ 63

Income tax

The provision for income tax is as follows:

	2004	2003	2002
Current income tax expense			
Current income tax – North America	$ 89	$ 43	$ –
Large Corporations Tax – North America	11	16	21
Current income tax – North Sea	2	23	(19)
Current income tax – Offshore West Africa	13	10	6
Current income tax – other	1	–	–
	116	92	8
Future income tax expense	474	338	375
Income tax	$ 590	$ 430	$ 383

The provision for income tax is different from the amount computed by applying the combined statutory Canadian federal and provincial income tax rates to earnings before taxes. The reasons for the difference are as follows:

	2004	2003	2002
Canadian statutory income tax rate	39.3%	41.1%	42.4%
Income tax provision at statutory rate	$ 849	$ 797	$ 418
Effect on income taxes of:			
Non-deductible portion of Canadian crown payments	221	285	211
Canadian resource allowance	(270)	(281)	(243)
Large Corporations Tax	11	16	21
Deductible UK petroleum revenue tax	(57)	(40)	(22)
Foreign tax rate differentials	(31)	20	(1)
Federal income tax rate reductions	–	(247)	–
Provincial income tax rate reductions	(66)	(31)	(21)
UK income tax rate increase	–	–	34
Non-taxable portion of foreign exchange	(36)	(103)	(21)
Other	(31)	14	7
Income tax	$ 590	$ 430	$ 383

The following table summarizes the temporary differences that give rise to the future income tax liability:

	2004	2003
Future income tax liabilities		
Property, plant and equipment	$ 3,760	$ 2,884
Timing of partnership items	1,254	1,095
Foreign exchange gain on long-term debt	102	90
Risk management	19	–
Other	43	14
Future income tax assets		
Asset retirement obligation	(418)	(365)
Capital loss carryforwards	(92)	–
Attributed Canadian Royalty Income	(54)	(58)
Stock-based compensation	(106)	(56)
Deferred petroleum revenue tax	(58)	(13)
Future income tax liability	$ 4,450	$ 3,591

A significant portion of the Company's North American taxable income is generated by partnerships. Income taxes are incurred on the partnerships' taxable income in the year following their inclusion in the Company's consolidated net earnings. Current income tax will vary and is dependent upon the amount of capital expenditures incurred in Canada and the way it is deployed.

During 2004, the Government of Alberta passed legislation to reduce its corporate income tax rate by 1.0% effective April 1, 2004. Accordingly, the Company's future income tax liability was reduced by $66 million.

During 2003, the Government of Alberta passed legislation to reduce its corporate income tax rate by 0.5% effective April 1, 2003. Also during 2003, the Canadian federal government passed legislation to change the taxation of resource income. The legislation reduces the corporate income tax rate on resource income from 28% to 21% over five years beginning January 1, 2003. Over the same period, the deduction for resource allowance is phased out and a deduction for actual crown royalties paid is phased in. The Company's future income tax liability was reduced by $31 million with respect to the Alberta corporate income tax rate reduction and by $247 million with respect to the Federal resource income tax rate changes.

9. Share capital

Authorized

200,000 Class 1 preferred shares with a stated value of $10.00 each.
Unlimited number of common shares without par value.

Issued

	2004		2003	
Common shares	Number of shares (thousands)	Amount	Number of shares (thousands)	Amount
Balance – beginning of year	267,463	$ 2,353	267,552	$ 2,304
Issued upon exercise of stock options	1,591	24	5,381	89
Previously recognized liability on stock options exercised for common shares	–	38	–	8
Purchase of common shares under Normal Course Issuer Bid	(873)	(7)	(5,470)	(48)
Balance – end of year	268,181	$ 2,408	267,463	$ 2,353

Share split

The Company's shareholders approved a subdivision or share split of its issued and outstanding common shares on a two-for-one basis at the Company's Annual and Special Meeting held on May 6, 2004. All common share and per common share amounts have been restated to retroactively reflect the share split.

Normal Course Issuer Bid

During 2004, the Company purchased 873,400 common shares at an average price of $38.01 per common share for a total cost of $33 million. The excess cost over book value of the common shares purchased was applied to reduce retained earnings.

During 2003, the Company purchased 5,469,600 common shares at an average price of $26.26 per common share for a total cost of $144 million. The excess cost over book value of the common shares purchased was applied to reduce retained earnings.

In January 2005, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 13,409,006 common shares or 5% of the Company's outstanding common shares on the date of announcement, during the 12-month period beginning January 24, 2005 and ending January 23, 2006. As at February 18, 2005, the Company had not purchased any additional shares under the renewed Normal Course Issuer Bid.

Dividend policy

The Company pays regular quarterly dividends in January, April, July and October of each year. On February 18, 2005, the Board of Directors set the Company's regular quarterly dividend at $0.1125 per common share (2004 – $0.10 per common share, 2003 – $0.075 per common share, 2002 – $0.0625 per common share) commencing with the April 1, 2005 payment.

Stock options

The Company's Option Plan provides for granting of stock options to directors, officers and employees. Stock options granted under the Option Plan have a maximum term of six years to expiry and vest equally over a five-year period starting on the first anniversary date of the grant. The exercise price of each stock option granted is determined as the closing market price of the common shares on the Toronto Stock Exchange on the day prior to the grant. Each stock option granted permits the holder to purchase one common share of the Company at the stated exercise price.

In June 2003, the Company approved a modification to its Option Plan providing the stock option holder the right to elect to receive a cash payment equal to the difference between the exercise price of the stock option and the market price of the Company's common shares on the date of surrender, multiplied by the number of common shares covered by the stock options surrendered, in lieu of receiving common shares. The modification to the Option Plan was accounted for prospectively.

For the year ended December 31, 2004, the Company recorded compensation expense of $249 million (2003 – $200 million). As at December 31, 2004, the total liability for expected cash settlements under the Option Plan is $323 million (2003 – $171 million), of which $243 million (2003 – $130 million) is included as a current liability. During the year ended December 31, 2004, cash payments of $80 million were made for 3,781,000 stock options surrendered (2003 – cash payments of $31 million for 2,674,000 stock options surrendered).

Prior to the modification, the Company disclosed pro-forma measures of net earnings and net earnings per common share as if stock options had been recognized as compensation expense estimated on the date of grant using the Black-Scholes option pricing model. As stock-based compensation is now reflected in the consolidated statement of earnings, the pro-forma disclosures are no longer required.

The following table summarizes information relating to stock options outstanding at December 31, 2004 and 2003:

	2004			2003		
	Stock options (thousands)		**Weighted average exercise price**	Stock options (thousands)		Weighted average exercise price
Outstanding – beginning of year	**17,789**	**$**	**19.72**	25,765	$	18.57
Granted	**4,861**	**$**	**35.89**	1,336	$	26.16
Exercised for common shares	**(1,591)**	**$**	**15.10**	(5,381)	$	16.57
Surrendered for cash settlement	**(3,781)**	**$**	**18.71**	(2,674)	$	17.36
Forfeited	**(1,017)**	**$**	**27.72**	(1,257)	$	21.39
Outstanding – end of year	**16,261**	**$**	**24.74**	17,789	$	19.72
Exercisable – end of year	**3,816**	**$**	**19.85**	4,646	$	17.33

The range of exercise prices of stock options outstanding and exercisable at December 31, 2004 is as follows:

	Stock options outstanding				**Stock options exercisable**		
Range of exercise prices	**Stock options outstanding** (thousands)	**Weighted average remaining term** (years)		**Weighted average exercise price**	**Stock options exercisable** (thousands)		**Weighted average exercise price**
$10.50 – $14.99	**15**	**0.40**	**$**	**13.16**	**15**	**$**	**13.16**
$15.00 – $19.99	**7,175**	**2.10**	**$**	**18.82**	**2,586**	**$**	**18.41**
$20.00 – $24.99	**3,830**	**3.05**	**$**	**22.50**	**1,082**	**$**	**22.39**
$25.00 – $29.99	**862**	**4.71**	**$**	**26.86**	**112**	**$**	**26.82**
$30.00 – $34.99	**2,978**	**5.12**	**$**	**33.80**	**21**	**$**	**33.93**
$35.00 – $39.99	**645**	**5.17**	**$**	**35.79**	**–**	**$**	**–**
$40.00 – $44.99	**318**	**5.60**	**$**	**40.99**	**–**	**$**	**–**
$45.00 – $48.99	**438**	**5.90**	**$**	**47.87**	**–**	**$**	**–**
	16,261	**3.30**	**$**	**24.74**	**3,816**	**$**	**19.85**

10. Foreign currency translation adjustment

The foreign currency translation adjustment represents the unrealized gain (loss) on the Company's net investment in self-sustaining foreign operations. Effective July 1, 2002, the Company designated certain US dollar denominated debt as a hedge against its net investment in US dollar-based self-sustaining foreign operations. Accordingly, translation gains and losses on this US dollar denominated debt are included in the foreign currency translation adjustment.

		2004		2003
Balance – beginning of year as previously reported	**$**	**17**	$	24
Change in accounting policy (note 2)		**(14)**		2
Balance – beginning of year as restated		**3**		26
Unrealized loss on translation of net investment		**(24)**		(124)
Hedge of net investment with US dollar denominated debt, net of tax		**15**		101
Balance – end of year	**$**	**(6)**	$	3

11. Net earnings per common share

The following table provides a reconciliation between basic and diluted amounts per common share:

(thousands of shares)	2004	2003	2002
Weighted average common shares outstanding – basic	268,112	268,470	255,766
Effect of dilutive stock options (1)	–	2,444	5,488
Assumed settlement of preferred securities with common shares	2,230	3,908	5,362
Weighted average common shares outstanding – diluted	270,342	274,822	266,616
Net earnings	$ 1,405	$ 1,403	$ 539
Interest on preferred securities, net of tax	5	5	6
Revaluation of preferred securities, net of tax	(4)	(18)	(1)
Diluted net earnings	$ 1,406	$ 1,390	$ 544
Net earnings per common share			
Basic	$ 5.24	$ 5.23	$ 2.11
Diluted	$ 5.20	$ 5.06	$ 2.04

(1) The modification of the Option Plan described in note 9 results in a liability and expense for all outstanding stock options. As such, the potential common shares associated with the stock options are not included in diluted earnings per share effective from June 2003, the date of the modification.

For the year ended December 31, 2002, 639,832 stock options with a weighted average exercise price of $24.17, were excluded from the calculation as their effect on per common share amounts was not dilutive.

12. Financial instruments

Risk management

On January 1, 2004, the fair values of all outstanding derivative financial instruments that were not designated as hedges for accounting purposes were recorded on the consolidated balance sheet, with an offsetting net deferred revenue amount (note 2). Subsequent changes in fair value are recognized on the consolidated balance sheet and in net earnings. The estimated fair value for all derivative financial instruments is based on third party indications. The following table reconciles the change in derivative financial instruments:

Asset (liability)	Risk management mark-to-market	Deferred revenue	Total unrealized gain/(loss)
Balance – beginning of year	$ 40	$ (40)	$ –
Change in fair value of existing financial instruments at beginning of year and new financial instruments entered in 2004	468	–	468
Put premiums	32	–	32
Realized risk management activities	(474)	–	(474)
Amortization of deferred revenue	–	14	14
Balance – end of year	66	(26)	$ 40
Less: current portion	34	(17)	
	$ 32	$ (9)	

Financial contracts

The Company's financial instruments recognized in the consolidated balance sheets consist of cash, accounts receivable, accounts payable, accrued liabilities, risk management activities, stock-based compensation and long-term debt.

The estimated fair values of financial instruments have been determined based on the Company's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a current market transaction.

The carrying value of cash, accounts receivable, accounts payable, accrued liabilities, stock-based compensation and long-term debt with variable interest rates approximate their fair value.

The estimated fair values of other financial instruments are as follows:

	2004 Carrying value	2004 Fair value	2003 Carrying value	2003 Fair value
Asset (liability)				
Derivative financial instruments	$ 66	$ 33	$ –	$ 16
Fixed rate notes	$ (3,175)	$ (3,364)	$ (2,664)	$ (2,880)

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The following summarizes transactions outstanding as at December 31, 2004:

	Remaining term	Volume	Average price	Index
Oil				
Oil price collars	Jan 2005 – Mar 2005	140,500 bbl/d	US$36.09 – US$45.32	WTI
	Apr 2005 – Jun 2005	150,500 bbl/d	US$39.98 – US$49.39	WTI
	Jul 2005 – Sep 2005	139,500 bbl/d	US$41.60 – US$51.35	WTI
	Oct 2005 – Dec 2005	139,500 bbl/d	US$41.60 – US$51.35	WTI
Oil puts	Jan 2005 – Mar 2005	99,000 bbl/d	US$29.21	WTI
	Apr 2005 – Jun 2005	123,000 bbl/d	US$29.89	WTI
	Jul 2005 – Sep 2005	50,000 bbl/d	US$31.09	WTI
	Oct 2005 – Dec 2005	50,000 bbl/d	US$29.81	WTI

	Remaining term	Volume	Average price	Index
Natural gas				
AECO collars	Jan 2005 – Mar 2005	640,000 GJ/d	C$6.24 – C$11.69	AECO
	Apr 2005 – Jun 2005	740,000 GJ/d	C$5.83 – C$7.89	AECO
	Jul 2005 – Sep 2005	640,000 GJ/d	C$5.88 – C$7.92	AECO
	Oct 2005 – Dec 2005	114,500 GJ/d	C$6.00 – C$8.08	AECO

	Remaining term	Amount ($ millions)	Average exchange rate (US$/C$)
Foreign currency			
Currency collars	Jan 2005 – Aug 2005	US$10/month	1.37 – 1.49

	Remaining term	Amount ($ millions)	Exchange rate (US$/C$)	Interest rate (US$)	Interest rate (C$)
Currency swap	Jan 2005 – Dec 2005	US$125	1.55	7.69%	7.30%
Currency forward	Jan 2005 – Jan 2005	US$471	1.18	n/a	n/a

	Remaining term	Amount ($ millions)	Fixed rate	Floating rate
Interest rate				
Swaps – fixed to floating	Jan 2005 – Jan 2005	US$200	7.20%	LIBOR (1) + 3.00%
	Jan 2005 – Jul 2006	US$200	6.70%	LIBOR (1) + 1.65%
	Jan 2005 – Jan 2007	US$200	7.20%	LIBOR (1) + 2.23%
	Jan 2005 – Oct 2012	US$350	5.45%	LIBOR (1) + 0.81%
	Jan 2005 – Dec 2014	US$350	4.90%	LIBOR (1) + 0.38%
Swaps – floating to fixed	Jan 2005 – Mar 2007	C$10	7.36%	CDOR (2)

(1) London Interbank Offered Rate
(2) Canadian Deposit Overnight Rate

Credit risk

Accounts receivable are mainly with customers in the oil and natural gas industry and are subject to normal industry credit risks. The Company minimizes this risk by entering into sales contracts with only highly rated entities. In addition, the Company reviews its exposure to individual companies on a regular basis and where appropriate, ensures that parental guarantees or letters of credit are in place to minimize the impact in the event of default. The Company is also exposed to possible losses in the event of non-performance by counterparties to derivative financial instruments; however, the Company minimizes this credit risk by entering into agreements with only highly rated financial institutions.

13. Commitments

The Company has committed to certain payments as follows:

		2005		2006		2007		2008		2009		Thereafter
Natural gas transportation	$	194	$	147	$	100	$	78	$	37	$	168
Oil transportation and pipeline	$	11	$	9	$	11	$	12	$	13	$	154
Offshore equipment operating lease	$	110	$	48	$	48	$	48	$	48	$	184
Baobab Project	$	99	$	–	$	–	$	–	$	–	$	–
Offshore drilling and other	$	125	$	8	$	–	$	–	$	–	$	–
Electricity	$	26	$	28	$	20	$	13	$	8	$	34
Office lease	$	21	$	21	$	22	$	23	$	24	$	30
Processing	$	5	$	2	$	–	$	–	$	–	$	–
Horizon Project	$	99	$	–	$	–	$	–	$	–	$	–

14. Supplemental disclosure of cash flow information

Changes in non-cash working capital were as follows:

		2004		2003		2002
Decrease (increase) in non-cash working capital						
Accounts receivable and other	**$**	**(329)**	$	35	$	(164)
Accounts payable		**39**		125		(145)
Accrued liabilities		**194**		122		154
Net change in non-cash working capital	**$**	**(96)**	$	282	$	(155)
Relating to:						
Operating activities	**$**	**(14)**	$	(48)	$	(157)
Financing activities		**6**		(11)		27
Investing activities		**(88)**		341		(25)
	$	**(96)**	$	282	$	(155)

Other cash flow information:		**2004**		2003		2002
Interest paid	**$**	**192**	$	178	$	132
Taxes paid	**$**	**218**	$	51	$	160

15. Segmented information

The Company's oil and natural gas activities are conducted in three geographic segments: North America, North Sea and Offshore West Africa. These activities relate to the exploration, development, production and marketing of oil, natural gas liquids and natural gas.

The Company's Horizon Project has been classified as a separate segment. As the bitumen will be recovered through mining operations, this project constitutes a distinct segment from oil and natural gas activities. There are currently no revenues for this project and all directly related expenditures have been capitalized.

Midstream activities include the Company's pipeline operations and an electricity co-generation system.

Activities that are not included in the above segments are included in the segmented information as other.

Inter segment eliminations include internal transportation and electricity charges.

15. Segmented information (continued)

	Oil and Natural Gas								
	North America			North Sea			Offshore West Africa		
	2004	2003	2002	**2004**	2003	2002	**2004**	2003	2002
Revenue	**$ 5,979**	$ 5,021	$ 3,719	**$ 1,317**	$ 953	$ 620	**$ 222**	$ 155	$ 102
Less: royalties	**(1,003)**	(868)	(564)	**(2)**	1	(33)	**(6)**	(5)	(3)
Revenue, net of royalties	**4,976**	4,153	3,155	**1,315**	954	587	**216**	150	99
Segmented expenses									
Production	**976**	845	656	**370**	314	229	**36**	38	35
Transportation	**256**	264	273	**32**	30	20	**–**	–	–
Depletion, depreciation and amortization	**1,444**	1,209	1,022	**265**	252	188	**53**	41	80
Asset retirement obligation accretion	**28**	26	20	**22**	36	48	**1**	–	–
Realized risk management activities	**362**	157	76	**112**	(9)	7	**–**	–	–
Total segmented expenses	**3,066**	2,501	2,047	**801**	623	492	**90**	79	115
Segmented earnings before the following	**$ 1,910**	$ 1,652	$ 1,108	**$ 514**	$ 331	$ 95	**$ 126**	$ 71	$ (16)
Non-segmented expenses									
Administration									
Stock-based compensation									
Interest									
Unrealized risk management activities									
Foreign exchange gain									
Total non-segmented expenses									
Earnings before taxes									
Taxes other than income tax									
Current income tax expense									
Future income tax expense									
Net earnings									

Capital expenditures

	2004				
	Cash consideration	**Non-cash consideration**	**Capital expenditures**	**Fair value adjustments (1)**	**Capitalized costs**
Oil and natural gas					
North America	**$ 3,329**	**$ 26**	**$ 3,355**	**$ 482**	**$ 3,837**
North Sea	**608**	**–**	**608**	**172**	**780**
Offshore West Africa	**296**	**–**	**296**	**–**	**296**
	4,233	**26**	**4,259**	**654**	**4,913**
Horizon Project	**291**	**–**	**291**	**–**	**291**
Midstream	**16**	**–**	**16**	**–**	**16**
Head office	**35**	**–**	**35**	**–**	**35**
	$ 4,575	**$ 26**	**$ 4,601**	**$ 654**	**$ 5,255**

(1) Asset retirement obligations, future income tax adjustments on non tax base assets, and other fair value adjustments.

Midstream 2004	Midstream 2003	Midstream 2002	Other 2004	Other 2003	Other 2002	Inter-segment Elimination 2004	Inter-segment Elimination 2003	Inter-segment Elimination 2002	Total 2004	Total 2003	Total 2002
$ 68	$ 61	$ 52	$ 1	$ –	$ –	$ (40)	$ (35)	$ (34)	$ 7,547	$ 6,155	$ 4,459
–	–	–	–	–	–	–	–	–	(1,011)	(872)	(600)
68	61	52	1	–	–	(40)	(35)	(34)	6,536	5,283	3,859
20	15	14	–	–	–	(2)	(3)	(3)	1,400	1,209	931
–	–	–	–	–	–	(38)	(32)	(31)	250	262	262
7	7	8	–	–	–	–	–	–	1,769	1,509	1,298
–	–	–	–	–	–	–	–	–	51	62	68
–	–	–	–	–	–	–	–	–	474	148	83
27	22	22	–	–	–	(40)	(35)	(34)	3,944	3,190	2,642
$ 41	$ 39	$ 30	$ 1	$ –	$ –	$ –	$ –	$ –	2,592	2,093	1,217
									115	87	61
									259	200	–
									189	201	203
									(40)	–	–
									(91)	(335)	(32)
									432	153	232
									2,160	1,940	985
									165	107	63
									116	92	8
									474	338	375
									$ 1,405	$ 1,403	$ 539

2003	Cash consideration	Non-cash consideration	Capital expenditures	Fair value adjustments (1)	Capitalized costs
Oil and natural gas					
North America	$ 1,769	$ –	$ 1,769	$ –	$ 1,769
North Sea	338	–	338	25	363
Offshore West Africa	176	–	176	–	176
	2,283	–	2,283	25	2,308
Horizon Project	152	–	152	–	152
Midstream	11	–	11	–	11
Head office	20	–	20	–	20
	$ 2,466	$ –	$ 2,466	$ 25	$ 2,491

Segmented property, plant and equipment, net	2004	2003
Oil and natural gas		
North America	$ 13,394	$ 10,990
North Sea	1,823	1,437
Offshore West Africa	909	667
Horizon Project	672	381
Midstream	209	200
Head office	57	39
	$ 17,064	$ 13,714

Segmented assets	2004	2003
Oil and natural gas		
North America	$ 14,455	$ 11,731
North Sea	2,036	1,562
Offshore West Africa	922	703
Horizon Project	672	381
Midstream	268	227
Head office	57	39
	$ 18,410	$ 14,643

16. Subsequent event

On February 9, 2005, the Company's Board of Directors unanimously authorized the Company to proceed with Phase 1 of the Horizon Oil Sands Project. The Horizon Project is designed as a phased development and includes two components: the mining of bitumen and an onsite upgrader. Phase 1 production is targeted to begin at 110,000 bbl/d of 34° API light sweet, synthetic crude oil ("SCO"). Phase 2 would increase production to 155,000 bbl/d of SCO. Phase 3 would further increase production to 232,000 bbl/d of SCO. Total expected capital costs for all three phases of the development are estimated at $10.8 billion. Capital costs for the first phase of the Horizon Project are estimated at $6.8 billion including a contingency reserve of $700 million, with $1.4 billion to be incurred in 2005, and $2.2 billion, $2.0 billion and $1.2 billion to be incurred in 2006, 2007 and 2008, respectively.

17. Differences between Canadian and United States generally accepted accounting principles

The Company's consolidated financial statements have been prepared in accordance with generally accepted accounting principles in Canada ("Canadian GAAP"). These principles conform in all material respects with those in the United States ("US GAAP") except for those noted below. Differences arising from US GAAP disclosure requirements are not addressed.

The application of US GAAP would have the following effects on consolidated net earnings as reported:

(millions of Canadian dollars, except per common share amounts)	Notes	2004	2003	2002
Net earnings – Canadian GAAP		$ 1,405	$ 1,403	$ 539
Adjustments, net of tax				
Depletion	(A)	4	4	(5)
Derivative financial instruments	(B)	(9)	(49)	29
Capitalized interest	(C)	16	–	–
Asset retirement obligation accretion	(D)	–	–	41
Cumulative effect of change in accounting policy	(D)	–	(4)	–
Tax effect of flow-through shares	(E)	–	–	(1)
Net earnings – US GAAP		$ 1,416	$ 1,354	$ 603
Net earnings – US GAAP per common share				
Basic		$ 5.28	$ 5.04	$ 2.36
Diluted		$ 5.24	$ 4.88	$ 2.28

Comprehensive income under US GAAP would be as follows:

(millions of Canadian dollars)	Notes		2004		2003		2002
Net earnings – US GAAP		$	1,416	$	1,354	$	603
Amortization of FAS 133 adjustment	(B)		8		20		31
Foreign currency translation adjustment	(F)		(9)		(23)		(49)
Comprehensive income		$	1,415	$	1,351	$	585

The application of US GAAP would have the following effects on the consolidated balance sheets as reported:

		2004					
(millions of Canadian dollars)	Notes		Canadian GAAP		Increase (Decrease)		US GAAP
Property, plant and equipment	(A)	$	17,064	$	(27)	$	17,037
Current portion of other long-term assets	(B)	$	34	$	(33)	$	1
Current portion of long-term debt	(B)	$	194	$	(44)	$	150
Future income tax	(A,B,C)	$	4,450	$	6	$	4,456
Shareholders' equity		$	7,324	$	(22)	$	7,302

		2003					
(millions of Canadian dollars)	Notes		Canadian GAAP		Increase (Decrease)		US GAAP
Property, plant and equipment	(A)	$	13,714	$	(60)	$	13,654
Current portion of other long-term assets	(B)	$	–	$	16	$	16
Future income tax	(A,B)	$	3,591	$	(3)	$	3,588
Shareholders' equity		$	6,006	$	(41)	$	5,965

Notes:

(A) Using Canadian full cost accounting rules, costs capitalized in each cost centre, net of future income taxes, are limited to an amount equal to the undiscounted, future net revenues from proved reserves using estimated future prices and costs, plus the carrying amount of unproved properties and major development projects (the "ceiling test"). Under the full cost method of accounting as set forth by the US Securities and Exchange Commission, the ceiling test differs from Canadian GAAP in that future net revenues from proved reserves are based on prices and costs as at the balance sheet date and are discounted at 10%.

(B) The Company uses certain derivative financial instruments to manage its commodity prices and foreign currency exposure in relation to future firmly committed and anticipated sales transactions. The Company also uses interest rate swaps to manage its interest rate exposure. Effective January 1, 2004, the Company prospectively adopted Accounting Guideline 13, "Hedging Relationships" and EIC 128, "Accounting for Trading, Speculative or Non-hedging Derivative Financial Instruments" for Canadian GAAP. Under Canadian GAAP, unrealized derivative financial instruments not designated as hedges are recorded in the consolidated financial statements at their fair value. Changes in the fair value of the undesignated derivative financial instruments in subsequent periods are recognized in consolidated net earnings. Derivative financial instruments designated as hedges are not recorded in the consolidated financial statements until realized. There is no requirement to recognize an ineffective portion of derivative financial instruments designated as hedges.

Effective January 1, 2001, the Company adopted Statement of Financial Accounting Standards ("FAS") 133 "Accounting for Derivative Instruments and Hedging Activities" and FAS 138 "Accounting for Certain Derivative Instruments and Certain Hedging Activities" to account for its commodity prices and interest rate swap derivative financial instruments under US GAAP. Under FAS 133, all derivative financial instruments are recognized in the consolidated balance sheets at their fair value. Changes in the fair value of derivative financial instruments are recognized in consolidated net earnings unless specific criteria for hedging are met, in which case the changes are recognized in comprehensive income. In 2003 and 2002, no derivative financial instruments were designated as hedges for US GAAP purposes.

In 2001, the adoption of FAS 133 resulted in the Company recognizing a derivative financial instruments liability of $183 million and a charge to comprehensive income of $124 million, net of future income tax recoveries of $59 million. Of the initial liability recognized on January 1, 2001, a loss of $8 million, net of future income tax recoveries of $3 million, was reclassified to net earnings during 2004 (2003 – a loss of $20 million, net of future income tax recoveries of $9 million; 2002 – a loss of $31 million, net of future income tax recoveries of $15 million).

Under US GAAP, foreign currency swap contracts used to hedge foreign currency exposure to anticipated, but not firmly committed, transactions cannot be accounted for as hedges. Accordingly, for US GAAP reporting, gains and losses from changes in the fair market value of foreign currency swap contracts related to these anticipated transactions are recognized in net earnings when those changes in market value occur.

(C) Under Canadian GAAP, capitalization of interest on projects constructed over time is discretionary. The Company has determined that the appropriate time to begin capitalizing interest on the Horizon Project is when sanction was received in February 2005. For US GAAP, capitalization of interest on projects constructed over time is mandatory and interest has been capitalized to the costs of construction in 2004.

(D) Under Canadian GAAP, when the asset retirement obligation standard was adopted prior period comparative balances were restated to reflect the effect of the new standard on that year. Under US GAAP, when the asset retirement obligation standard was adopted the cumulative effect of the new standard on prior periods was included in earnings in the year adopted.

(E) Under Canadian GAAP, the future income tax effect of flow-through shares is deducted from share capital. However, under US GAAP, the future income tax effect of flow-through shares is expensed immediately.

(F) Under US GAAP, exchange gains and losses arising from the translation of self-sustaining foreign operations are included in comprehensive income.

18. Recently issued accounting standards

Financial Instruments

In January 2005, the CICA issued Section 3855 "Financial Instruments – Recognition and Measurement". This Section prescribes when a financial asset, financial liability, or non-financial derivative is to be recognized on the balance sheet and at what amount – sometimes using fair value; other times using cost-based measures. This Section also specifies how financial instruments gains and losses are to be presented. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Transitional provisions for this Section are complex and vary based on the type of financial instruments under consideration. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Hedges

In January 2005, the CICA issued Section 3865 "Hedges". This Section expands on existing Accounting Guideline 13 – Hedging Relationships, and Section 1650 "Foreign Currency Translation", by specifying how hedge accounting is applied and what disclosure are necessary when it is applied. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Retroactive application of this Section is not permitted. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Comprehensive Income

In January 2005, the CICA issued Section 1530 "Comprehensive Income". This Section introduces new standards for reporting and display of comprehensive income. Comprehensive income is the change in equity (net assets) of a company during a reporting period from transactions and other events and circumstances from non-owner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Financial statements of prior periods are required to be restated for certain comprehensive income items. In addition, a company is encouraged, but not required to present reclassification adjustments, in comparative financial statements provided for earlier periods. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Equity

In January 2005, the CICA issued Section 3251 "Equity". This Section replaces Section 3250 "Surplus". It establishes standards for the presentation of equity and changes in equity during a reporting period. This Section applies to interim and annual financial statements relating to fiscal years beginning on or after October 31, 2006. Earlier adoption is permitted only as of the beginning of a fiscal year ending on or after December 31, 2004. The Company plans to adopt this Section on January 1, 2007. Financial statements of prior periods are required to be restated for certain specified adjustments. For all other items, comparative financial statements are presented are not restated, but an adjustment to the opening balance of accumulated other comprehensive income may be required. In addition, a company is encouraged, but not required to present reclassification adjustments, in comparative financial statements provided for earlier periods. The effect on the Company's consolidated financial statements cannot be reasonably determined at this time.

Supplementary Oil & Gas Information (unaudited)

This supplementary oil and natural gas information is provided in accordance with the United States FAS 69, "Disclosures about Oil and Gas Producing Activities", and where applicable is reconciled to the US GAAP financial information.

Net proved oil and natural gas reserves
The Company retains qualified independent reserves evaluators to evaluate the Company's proved oil and natural gas reserves.

- For the year ended December 31, 2004, the reports by Sproule Associates Limited ("Sproule") and Ryder Scott Company covered 100% of the Company's reserves;
- For the year ended December 31, 2003, the reports by Sproule covered 100% of the Company's reserves; and
- For the year ended December 31, 2002, the reports by Sproule covered 89% of the Company's reserves.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and natural gas liquids that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Estimates of oil and natural gas reserves are subject to uncertainty and will change as additional information regarding producing fields and technology becomes available and as future economic and operating conditions change.

The following table summarizes the Company's proved and proved developed oil and natural gas reserves, net of royalties, as at December 31, 2004, 2003 and 2002:

Oil and natural gas liquids (mmbbl)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2001	583	78	60	721
Extensions and discoveries	26	1	14	41
Purchases of reserves in place	44	114	–	158
Sales of reserves in place	(1)	(18)	–	(19)
Production	(55)	(13)	(2)	(70)
Revisions of previous estimates	(26)	40	3	17
Reserves, December 31, 2002	571	202	75	848
Extensions and discoveries	55	–	13	68
Improved recovery	9	–	–	9
Purchases of reserves in place	7	27	–	34
Sales of reserves in place	–	–	–	–
Production	(56)	(21)	(4)	(81)
Revisions of previous estimates	2	14	1	17
Reserves, December 31, 2003	588	222	85	895
Extensions and discoveries	**41**	**35**	**–**	**76**
Improved recovery	**1**	**10**	**–**	**11**
Purchases of reserves in place	**36**	**38**	**–**	**74**
Sales of reserves in place	**–**	**–**	**–**	**–**
Production	**(66)**	**(24)**	**(4)**	**(94)**
Revisions of previous estimates	**48**	**22**	**34**	**104**
Reserves, December 31, 2004	**648**	**303**	**115**	**1,066**
Net proved developed reserves:				
December 31, 2001	344	51	20	415
December 31, 2002	340	107	27	474
December 31, 2003	348	138	23	509
December 31, 2004	**367**	**218**	**20**	**605**

Natural gas (bcf)	North America	North Sea	Offshore West Africa	Total
Net proved reserves				
Reserves, December 31, 2001	2,064	94	67	2,225
Extensions and discoveries	106	–	4	110
Purchases of reserves in place	699	18	–	717
Sales of reserves in place	(3)	(56)	–	(59)
Production	(346)	(10)	(1)	(357)
Revisions of previous estimates	(74)	25	1	(48)
Reserves, December 31, 2002	2,446	71	71	2,588
Extensions and discoveries	301	–	6	307
Improved recovery	8	–	–	8
Purchases of reserves in place	50	19	–	69
Sales of reserves in place	(3)	–	–	(3)
Production	(355)	(17)	(3)	(375)
Revision of previous estimates	(21)	(11)	(10)	(42)
Reserves, December 31, 2003	2,426	62	64	2,552
Extensions and discoveries	**408**	**–**	**–**	**408**
Improved recovery	**6**	**–**	**–**	**6**
Purchases of reserves in place	**182**	**10**	**–**	**192**
Sales of reserves in place	**(8)**	**–**	**–**	**(8)**
Production	**(383)**	**(18)**	**(3)**	**(404)**
Revision of previous estimates	**(40)**	**(27)**	**11**	**(56)**
Reserves, December 31, 2004	**2,591**	**27**	**72**	**2,690**
Net proved developed reserves:				
December 31, 2001	1,845	19	16	1,880
December 31, 2002	2,185	57	27	2,269
December 31, 2003	2,140	46	12	2,198
December 31, 2004	**2,213**	**12**	**5**	**2,230**

Capitalized costs related to oil and natural gas activities

	2004			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Proved properties	**$ 18,749**	**$ 2,518**	**$ 565**	**$ 21,832**
Unproved properties	**1,028**	**44**	**536**	**1,608**
	19,777	**2,562**	**1,101**	**23,440**
Less: accumulated depletion and depreciation	**(6,410)**	**(739)**	**(192)**	**(7,341)**
Net capitalized costs	**$ 13,367**	**$ 1,823**	**$ 909**	**$ 16,099**

	2003			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 15,125	$ 1,917	$ 568	$ 17,610
Unproved properties	789	56	237	1,082
	15,914	1,973	805	18,692
Less: accumulated depletion and depreciation	(4,984)	(534)	(140)	(5,658)
Net capitalized costs	$ 10,930	$ 1,439	$ 665	$ 13,034

	2002			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Proved properties	$ 13,197	$ 1,559	$ 480	$ 15,236
Unproved properties	667	62	132	861
	13,864	1,621	612	16,097
Less: accumulated depletion and depreciation	(3,679)	(344)	(94)	(4,117)
Net capitalized costs	$ 10,185	$ 1,277	$ 518	$ 11,980

Costs incurred in oil and natural gas activities

(millions of Canadian dollars)		2004 North America		2004 North Sea		2004 Offshore West Africa		2004 Total
Property acquisitions								
Proved	**$**	**1,748**	**$**	**302**	**$**	**-**	**$**	**2,050**
Unproved		**298**		**4**		**-**		**302**
Exploration		**290**		**11**		**37**		**338**
Development		**1,403**		**308**		**259**		**1,970**
Finding and development costs		**3,739**		**625**		**296**		**4,660**
Asset retirement costs		**98**		**165**		**(10)**		**253**
Actual retirement expenditures		**(32)**		**-**		**-**		**(32)**
Costs incurred	**$**	**3,805**	**$**	**790**	**$**	**286**	**$**	**4,881**

(millions of Canadian dollars)		2003 North America		2003 North Sea		2003 Offshore West Africa		2003 Total
Property acquisitions								
Proved	$	236	$	100	$	–	$	336
Unproved		116		23		–		139
Exploration		190		47		28		265
Development		1,227		193		148		1,568
Finding and development costs		1,769		363		176		2,308
Asset retirement costs		80		59		9		148
Actual retirement expenditures		(30)		(1)		(9)		(40)
Costs incurred	$	1,819	$	421	$	176	$	2,416

(millions of Canadian dollars)		2002 North America		2002 North Sea		2002 Offshore West Africa		2002 Total
Property acquisitions								
Proved	$	3,367	$	373	$	–	$	3,740
Unproved		369		28		30		427
Exploration		96		10		81		187
Development		607		145		74		826
Costs incurred	$	4,439	$	556	$	185	$	5,180

Results of operations from oil and natural gas producing activities

The Company's results of operations from oil and natural gas producing activities for the years ended December 31, 2004, 2003 and 2002 are summarized in the following tables:

	2004			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 4,579	$ 1,203	$ 216	$ 5,998
Production	(976)	(370)	(36)	(1,382)
Transportation	(256)	(32)	–	(288)
Depletion, depreciation and amortization	(1,438)	(265)	(53)	(1,756)
Asset retirement obligation accretion	(28)	(22)	(1)	(51)
Petroleum revenue tax	–	(145)	–	(145)
Income tax	(690)	(148)	(44)	(882)
Results of operations	$ 1,191	$ 221	$ 82	$ 1,494

	2003			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 3,961	$ 962	$ 150	$ 5,073
Production	(845)	(314)	(38)	(1,197)
Transportation	(263)	(30)	(1)	(294)
Depletion, depreciation and amortization	(1,203)	(250)	(42)	(1,495)
Asset retirement obligation accretion	(23)	(39)	(1)	(63)
Petroleum revenue tax	–	(97)	–	(97)
Income tax	(673)	(93)	(24)	(790)
Results of operations	$ 954	$ 139	$ 44	$ 1,137

	2002			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Oil and natural gas revenue, net of royalties	$ 3,045	$ 579	$ 99	$ 3,723
Production	(656)	(229)	(35)	(920)
Transportation	(273)	(20)	–	(293)
Depletion, depreciation and amortization	(1,024)	(193)	(80)	(1,297)
Petroleum revenue tax	–	(51)	–	(51)
Income tax	(431)	(34)	11	(454)
Results of operations	$ 661	$ 52	$ (5)	$ 708

Standardized measure of discounted future net cash flows from proved oil and natural gas reserves and changes therein

The following standardized measure of discounted future net cash flows from proved oil and natural gas reserves has been computed using year-end sales prices and costs and year-end statutory income tax rates. A discount factor of 10% has been applied in determining the standardized measure of discounted future net cash flows. The Company does not believe that the standardized measure of discounted future net cash flows will be representative of actual future net cash flows and should not be considered to represent the fair value of the oil and natural gas properties. Actual net cash flows will differ from the presented estimated future net cash flows due to several factors including:

- Future production will include production not only from proved properties, but may also include production from probable and potential reserves;
- Future production of oil and natural gas from proved properties will differ from reserves estimated;
- Future production rates will vary from those estimated;
- Future rather than year-end sales prices and costs will apply;
- Economic factors such as interest rates, income tax rates, regulatory and fiscal environments and operating conditions will change;
- Future estimated income taxes do not take into account the effects of future exploration expenditures; and
- Future development and site restoration costs will differ from those estimated.

Future net revenues, development, production and restoration costs have been based upon the estimates referred to above.

The following tables summarize the Company's future net cash flows relating to proved oil and natural gas reserves based on the standardized measure as prescribed in FAS 69:

	2004			
(millions of Canadian dollars)	**North America**	**North Sea**	**Offshore West Africa**	**Total**
Future cash inflows	**$ 31,727**	**$ 15,526**	**$ 5,249**	**$ 52,502**
Future production costs	**(10,995)**	**(6,302)**	**(1,137)**	**(18,434)**
Future development and site restoration costs	**(2,944)**	**(2,832)**	**(631)**	**(6,407)**
Future income taxes	**(6,438)**	**(3,783)**	**(1,242)**	**(11,463)**
Future net cash flows	**11,350**	**2,609**	**2,239**	**16,198**
10% annual discount for timing of future cash flows	**(4,385)**	**(691)**	**(634)**	**(5,710)**
Standardized measure of future net cash flows	**$ 6,965**	**$ 1,918**	**$ 1,605**	**$ 10,488**

	2003			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 32,720	$ 9,099	$ 3,192	$ 45,011
Future production costs	(9,480)	(3,015)	(1,179)	(13,674)
Future development and site restoration costs	(2,393)	(1,749)	(697)	(4,839)
Future income taxes	(7,295)	(2,801)	–	(10,096)
Future net cash flows	13,552	1,534	1,316	16,402
10% annual discount for timing of future cash flows	(6,203)	(336)	(432)	(6,971)
Standardized measure of future net cash flows	$ 7,349	$ 1,198	$ 884	$ 9,431

	2002			
(millions of Canadian dollars)	North America	North Sea	Offshore West Africa	Total
Future cash inflows	$ 34,980	$ 9,682	$ 3,206	$ 47,868
Future production costs	(7,238)	(3,250)	(911)	(11,399)
Future development and site restoration costs	(1,770)	(1,691)	(616)	(4,077)
Future income taxes	(8,046)	(2,991)	–	(11,037)
Future net cash flows	17,926	1,750	1,679	21,355
10% annual discount for timing of future cash flows	(7,361)	(434)	(556)	(8,351)
Standardized measure of future net cash flows	$ 10,565	$ 1,316	$ 1,123	$ 13,004

The principal sources of change in the standardized measure of discounted future net cash flows are summarized in the following table:

(millions of Canadian dollars)	**2004**	2003	2002
Sales of oil and natural gas produced, net of production costs	**$ (4,331)**	$ (3,582)	$ (2,510)
Net changes in sales prices and production costs	**(553)**	(2,750)	8,453
Extensions, discoveries and improved recovery	**2,120**	1,360	972
Changes in estimated future development costs	**(894)**	(346)	(1,284)
Purchases of proved reserves in place	**1,386**	594	4,973
Sales of proved reserves in place	**(20)**	(8)	(494)
Revisions of previous reserve estimates	**1,431**	144	360
Accretion of discount	**1,558**	2,000	794
Changes in production timing and other	**1,357**	(1,411)	502
Net change in income taxes	**(997)**	426	(4,723)
Net change	**1,057**	(3,573)	7,043
Balance – beginning of year	**9,431**	13,004	5,961
Balance – end of year	**$ 10,488**	$ 9,431	$ 13,004

Ten-Year Review

Years ended December 31	2004	2003 (1)	2002 (1)	2001 (1)	2000 (1)	1999 (1)	1998 (1)	1997 (1)	1996 (1)	1995 (1)
FINANCIAL INFORMATION										
(millions of Canadian dollars, except per share amounts)										
Net earnings	**1,405**	1,403	539	639	758	213	31	104	88	38
Per share - basic (2)	**$ 5.24**	$ 5.23	$ 2.11	$ 2.64	$ 3.25	$ 1.03	$ 0.16	$ 0.53	$ 0.53	$ 0.27
Cash flow from operations (3)	**3,769**	3,160	2,254	1,920	1,884	724	444	503	360	154
Per share - basic (2)	**$ 14.06**	$ 11.77	$ 8.82	$ 7.92	$ 8.07	$ 3.48	$ 2.24	$ 2.57	$ 2.16	$ 1.11
Capital expenditures, net of dispositions (including business combinations)	**4,633**	2,506	4,069	1,885	2,823	1,901	610	1,119	1,204	239
Balance sheet information										
Working capital (deficiency) surplus	**(652)**	(505)	(14)	(6)	(77)	36	58	(19)	(1)	10
Property, plant and equipment, net	**17,064**	13,714	12,934	8,766	7,439	4,679	3,135	2,831	1,993	884
Total assets	**18,410**	14,643	13,793	9,290	8,051	4,976	3,329	3,016	2,144	948
Long-term debt	**3,538**	2,748	4,200	2,788	2,573	2,157	1,426	1,136	588	238
Shareholders' equity	**7,324**	6,006	4,754	3,928	3,297	1,962	1,317	1,250	1,108	519
SHARE INFORMATION										
Common shares outstanding (thousands)	**268,181**	267,463	267,552	242,402	244,558	222,908	199,618	197,638	194,766	148,148
Weighted average shares outstanding (thousands)	**268,112**	268,470	255,766	242,600	233,402	207,812	198,662	196,084	166,492	138,638
Dividends per common share	**$ 0.40**	$ 0.30	$ 0.25	$ 0.20	$ –	$ –	$ –	$ –	$ –	$ –
Trading statistics										
TSX – C$										
Trading volume (thousands)	**303,012**	295,351	309,658	267,488	283,706	215,230	205,220	201,076	198,444	121,870
Share price ($/share)										
High	**$ 55.15**	$ 33.61	$ 27.27	$ 26.18	$ 28.10	$ 19.30	$ 15.75	$ 22.13	$ 19.70	$ 10.13
Low	**$ 31.91**	$ 22.60	$ 18.80	$ 17.95	$ 14.90	$ 9.90	$ 9.13	$ 14.45	$ 9.63	$ 5.38
Close	**$ 51.25**	$ 32.69	$ 23.40	$ 19.16	$ 20.75	$ 17.63	$ 11.50	$ 15.30	$ 18.80	$ 10.00
NYSE – US$										
Trading volume (thousands)	**62,734**	23,458	15,932	10,382	1,586	–	–	–	–	–
Share price ($/share)										
High	**$ 44.74**	$ 25.70	$ 17.44	$ 17.26	$ 18.91	$ –	$ –	$ –	$ –	$ –
Low	**$ 23.88**	$ 14.63	$ 11.78	$ 11.40	$ 12.38	$ –	$ –	$ –	$ –	$ –
Close	**$ 42.77**	$ 25.22	$ 14.84	$ 12.20	$ 13.75	$ –	$ –	$ –	$ –	$ –
RATIOS										
Debt to cash flow	**1.0x**	0.9x	1.9x	1.5x	1.4x	3.0x	3.2x	2.3x	1.6x	1.5x
Debt to book capitalization	**33.8%**	32.8%	47.1%	41.7%	44.0%	52.4%	52.0%	47.6%	34.7%	31.4%
Debt to EBITDA	**0.9x**	0.8x	1.7x	1.4x	1.2x	2.6x	2.9x	4.8x	3.0x	2.7x
Daily production, before royalties, per thousand shares (boe/d)	**1.9**	1.7	1.6	1.5	1.3	0.9	0.9	0.9	0.6	0.5
Reserves, before royalties, per common share (boe)	**8.7**	7.9	6.7	6.1	5.7	4.8	3.8	3.4	2.6	1.7
Net asset value per common share (4)	**$ 68.63**	$ 48.58	$ 39.18	$ 33.74	$ 42.67	$ 24.30	$ 15.87	$ 13.70	$ 12.92	$ 9.20

(1) Restated for changes in accounting policies (see consolidated financial statements note 2).

(2) Restated to reflect two-for-one share split in May 2004.

(3) Cash flow from operations is a non-GAAP term that represents net earnings adjusted for non-cash items. The Company evaluates its performance and that of its business segments based on net earnings and cash flow.

(4) Based upon 10% discounted, escalated price pre-tax proved and probable net asset values as reported in the Company's AIF, with $75/acre added for undeveloped land, less long-term debt and existing asset liabilities. Includes value of midstream assets. See reserves disclosures on pages 11 to 15.

Years ended December 31	2004	2003	2002	2001	2000	1999	1998	1997	1996	1995
OPERATING INFORMATION										
Crude oil and NGLs (mmbbl)										
Proved reserves, before royalties										
North America	**695**	672	665	644	643	554	284	257	136	51
North Sea	**303**	222	203	83	102	–	–	–	–	–
Offshore West Africa	**125**	106	94	61	36	–	–	–	–	–
	1,123	1,000	962	788	781	554	284	257	136	51
Proved and probable reserves, before royalties										
North America	**992**	977	742	740	731	640	380	329	185	74
North Sea	**415**	317	277	106	134	–	–	–	–	–
Offshore West Africa	**214**	187	162	111	46	–	–	–	–	–
	1,621	1,481	1,181	957	911	640	380	329	185	74
Natural gas (bcf)										
Proved reserves, before royalties										
North America	**3,202**	3,006	3,048	2,566	2,360	2,183	1,901	1,716	1,566	908
North Sea	**27**	62	71	94	91	–	–	–	–	–
Offshore West Africa	**81**	86	90	69	65	–	–	–	–	–
	3,310	3,154	3,209	2,729	2,516	2,183	1,901	1,716	1,566	908
Proved and probable reserves, before royalties										
North America	**4,100**	3,611	3,450	2,915	2,762	2,547	2,211	2,078	1,926	1,111
North Sea	**57**	101	89	118	114	–	–	–	–	–
Offshore West Africa	**102**	111	120	96	84	–	–	–	–	–
	4,259	3,823	3,659	3,129	2,960	2,547	2,211	2,078	1,926	1,111
Total proved reserves before royalties (mmboe)	**1,674**	1,526	1,497	1,243	1,200	918	601	543	397	202
Total proved and probable reserves before royalties (mmboe)	**2,330**	2,118	1,791	1,479	1,404	1,065	749	675	506	259
Daily production, before royalties										
Crude oil and NGLs (mbbl/d)										
North America	**206**	175	169	167	155	87	76	71	37	17
North Sea	**65**	57	39	36	17	–	–	–	–	–
Offshore West Africa	**12**	10	7	3	2	–	–	–	–	–
	283	242	215	206	174	87	76	71	37	17
Natural gas (mmcf/d)										
North America	**1,330**	1,245	1,204	906	793	721	673	626	499	305
North Sea	**50**	46	27	12	1	–	–	–	–	–
Offshore West Africa	**8**	8	1	–	–	–	–	–	–	–
	1,388	1,299	1,232	918	794	721	673	626	499	305
Total production, before royalties (mboe/d)	**514**	459	421	359	306	207	188	175	120	68
Product pricing (1)										
Average crude oil and NGLs ($/bbl)	**37.99**	32.66	31.22	23.45	31.89	22.26	11.98	18.99	24.73	20.00
Average natural gas price ($/mcf)	**6.50**	6.21	3.77	5.45	4.92	2.52	2.11	1.97	1.67	1.34

(1) Including transportation costs and excluding risk management activities.

Corporate Information

Board of Directors

Catherine M. Best (1)
Executive Vice-President,
Risk Management & Chief Financial Officer,
Calgary Health Region
Calgary, Alberta

N. Murray Edwards
President, Edco Financial Holdings Ltd.
Calgary, Alberta

Ambassador Gordon D. Giffin (1)
Senior Partner, McKenna Long & Aldridge LLP
Atlanta, Georgia

John G. Langille
President, Canadian Natural Resources Limited
Calgary, Alberta

Keith A. J. MacPhail (1)
Chairman, President & Chief Executive Officer,
Bonavista Petroleum Ltd.
Calgary, Alberta

Allan P. Markin
Chairman of the Board,
Canadian Natural Resources Limited
Calgary, Alberta

James S. Palmer, C.M.,A.O.E.,Q.C. (1)
Chairman, Burnet, Duckworth & Palmer LLP
Calgary, Alberta

Eldon R. Smith, M.D. (1)
Professor and Former Dean,
Faculty of Medicine, University of Calgary
Calgary, Alberta

David A. Tuer (1)
President & Chief Executive Officer,
Hawker Resources Inc.
Calgary, Alberta

Board of Director Committees

Audit Committee
Catherine M. Best – Chair
Ambassador Gordon D. Giffin
David A. Tuer

Compensation Committee
James S. Palmer – Chair
Catherine M. Best
Keith A. J. MacPhail
Eldon R. Smith

Nominating and Corporate Governance Committee
Ambassador Gordon D. Giffin – Chair
Eldon R. Smith
David A. Tuer

Reserves Committee
David A. Tuer – Chair
N. Murray Edwards
Keith A. J. MacPhail
Allan P. Markin
James S. Palmer

Health, Safety and Environmental Committee
Eldon R. Smith – Chair
N. Murray Edwards
Keith A. J. MacPhail
Allan P. Markin
James S. Palmer

(1) Defined as Unrelated under the Corporate Governance Guidelines issued by the Toronto Stock Exchange; and defined as Independent under the United States Sarbanes-Oxley Act of 2002, and the listing standards of the New York Stock Exchange.

Corporate Governance

Canadian Natural is in compliance with each of the existing corporate governance guidelines of the Toronto Stock Exchange and is substantially in compliance with the New York Stock Exchange Corporate Governance Listing Standards. There are no significant differences in Canadian Natural's current corporate governance practices to those currently mandated by the New York Stock Exchange Listing Standards.

Canadian Natural has included as exhibits to its Annual Report on Form 40-F for the 2004 fiscal year filed with the United States Securities and Exchange Commission certificates of the Chief Executive Officer and Chief Financial Officer certifying the quality of its public disclosure.

Officers

Allan P. Markin
Chairman of the Board

N. Murray Edwards
Vice-Chairman of the Board

John G. Langille
President

Steve W. Laut
Chief Operating Officer

Réal M. Cusson
Senior Vice-President, Marketing

Réal J.H. Doucet
Senior Vice-President, Oil Sands

Allen M. Knight
Senior Vice-President, International & Corporate Development

Tim S. McKay
Senior Vice-President, North American Operations

Douglas A. Proll
Senior Vice-President, Finance

Lyle G. Stevens
Senior Vice-President, Exploitation

Jeff W. Wilson
Senior Vice-President, Exploration

Mary-Jo E. Case
Vice-President, Land

Wayne M. Chorney
Vice-President, Development Operations

William R. Clapperton
Vice-President, Regulatory, Stakeholder & Environmental Affairs

Martin Cole
Vice-President and Managing Director, CNR International (U.K.) Limited

Gordon M. Coveney
Vice-President, Exploration – East

Randall S. Davis
Vice-President, Financial Accounting & Controls

Jerry W. Harvey
Vice-President, Commercial Operations

Peter J. Janson
Vice-President, Engineering Integration

Terry J. Jocksch
Vice-President, Exploitation – East

Christopher M. Kean
Vice-President, Utilities & Offsites

Philip A. Keele
Vice-President, Mining

Cameron S. Kramer
Vice-President, Field Operations

León Miura
Vice-President, Upgrading

S. John Parr
Vice-President, Production – East

David A. Payne
Vice-President, Exploitation – West

Bill R. Peterson
Vice-President, Production – West

John C. Puckering
Vice-President, Site Development

Sheldon L. Schroeder
Vice-President, Project Control

Ken W. Stagg
Vice-President, Exploration – West

Lynn M. Zeidler
Vice-President, Bitumen Production

Bruce E. McGrath
Corporate Secretary

Kimberly I. McKay
Treasurer

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Vice-President and Managing Director

Registrar and Transfer Agent

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Calgary, Alberta
Toronto, Ontario

Computershare Investor Services LLC
New York, New York

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Independent Qualified Reserves Evaluators

Gilbert Laustsen Jung Associates Ltd.
Calgary, Alberta

Ryder Scott Company
Calgary, Alberta

Sproule Associates Limited
Calgary, Alberta

Stock Listing

The Toronto Stock Exchange
CNQ
CNQ.U (Denotes trading in US funds)

The New York Stock Exchange
CNQ

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Horizon Bridge photos courtesy of Associated Engineering / Kiewit Management Co.

Baobab subsea equipment schematic courtesy of FMC/ID

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Canadian Natural

Important dates

Interim Report First Quarter 2005
Wednesday, May 4, 2005

Annual and Special Meeting of the Shareholders
Thursday, May 5, 2005

Interim Report Second Quarter 2005
Wednesday, August 3, 2005

Interim Report Third Quarter 2005
Wednesday, November 2, 2005

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